**CALIFORNIA ENERGY COMMISSION**

# A PRELIMINARY ENVIRONMENTAL PROFILE OF CALIFORNIA'S IMPORTED ELECTRICITY

IN SUPPORT OF THE
*2005 ENVIRONMENTALPERFORMANCE*
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STAFF REPORT

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# DISCLAIMER

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# CHAPTER 1: INTRODUCTION

California imports about 31 percent of its annual electricity supply from out-of-state generating units, although amounts vary from year to year. Coal, hydropower, natural gas, and nuclear plants located throughout the West supply portions of the state's electricity. As noted in the *2003 Environmental Performance Report* (EPR), energy imported into California results in fewer impacts to California's natural resources and positive effects for the economies of other states and countries. However, electricity generated in other states and countries for import to California markets creates environmental impacts in those locales. Most users of this imported electricity are unaware of its impacts to air, water and biological resources.

California utilities own more than 6,200 megawatts (MW) of out-of-state power, and about 75 percent of this power (4,744 MW) comes from coal. Coal is a low cost, plentiful, indigenous resource and is used to generate electricity in much of the United States (U.S.). However, coal-fired generation results in higher levels of criteria, toxic and greenhouse gas emissions, including mercury and lead, in contrast to other fuel sources such as natural gas. Hydropower facilities in the Pacific Northwest supply over 7,000 MW of power to California and have significant effects on salmon populations. To better understand the environmental effects of out-of-state generated electricity, additional information is needed on out-of-state coal and hydropower facilities that provide electricity to California, and on other out-of-state fuel resources used to generate electricity.

This report provides a preliminary environmental assessment of the impacts to air quality, water resources, and biological resources associated with California's imported energy from coal, hydropower, natural gas, nuclear, and renewable energy resources (wind, geothermal and biomass). For purposes of this report two regions (Northwest and Southwest) were studied. The western states and neighboring countries that make up these two regions, and their respective predominant energy source, are listed below:

| **Northwest Region** | | **Southwest Region** | |
|---|---|---|---|
| **State/Province** | **Energy Source** | **State/Province** | **Energy Source** |
| Idaho (ID) | Hydropower | Arizona (AZ) | Coal |
| Montana (MT) | Coal | Colorado (CO) | Coal |
| Oregon (OR) | Hydropower | Nevada (NV) | Coal |
| Washington (WA) | Hydropower | New Mexico (NM) | Coal |
| Wyoming (WY) | Coal | Utah (UT) | Coal |
| Canada | Hydropower | Mexico | Oil |

In light of the significant level of energy already imported into California and the potential for development of additional power plants in the West (with subsequent importation to California), the Energy Commission is particularly interested in addressing the following questions:

- What energy resource contributes most to imported power?
- How will the energy mix change in the future?
- What are the major environmental issues associated with each type of imported power?
- How do effects or issues vary by region?
- Will new environmental regulations significantly alter effects from existing or proposed power plants?
- What are emerging environmental technologies that could reduce effects in the near-term or long-term and will new power plants incorporate these new technologies?

## Report Findings

This report is based on an evaluation of power plant data and an extensive literature search and makes the following findings regarding electricity generation from out-of-state facilities:

- **Coal Is An Important But Hidden Part of California's Electricity Supply:** California utilities own more than 6,200 MW of out-of-state power. About 75 percent of this power (4,744 MW) comes from coal. From 2001 to 2003, total coal imports from California-owned and other coal plants in the western States averaged 80,000 gigawatt-hours (GWh) per year, or 31 percent of the electricity consumed in California.
- **Air Emissions For Imported Electricity Are Higher Than For In-State Generation:** Air pollutant emissions from imported out-of-state generation sources are on average considerably higher per megawatt hour (MWh) of generation than from in-state generation. The California power generation fleet's average emission factor for NOx was 0.36 pounds per MWh between 2001 and 2003, while the NOx emission factor for the Western States averaged 1.4 pounds per MWh – nearly four times higher. Unlike California, the air pollutant emissions from power generation can be a significant fraction of certain pollutants (such as $SO_2$) emitted annually. Air pollutant emissions from certain coal-fired plants are contributors to significant Class 1 Area visibility problems. For example, emissions from the Mohave and Navajo power plants contribute to the Grand Canyon's significant visibility problems. Generally, though, most western non-attainment areas are located around urban areas where emissions from power generation are small compared with emissions from other typical urban activities.

- **Coal Generation is a Large and Growing Percentage of the Western Resource Mix:** The primary fuel source for Western North America is coal. There are 31,857 MW of coal-fired capacity in the Western States: 33 percent of all generation capacity (excluding California). About 90 percent of coal-fired plants use Pulverized Coal Combustion (PCC) technology, which produces more air pollutant emissions than newer technologies and natural gas plants. While 2,760 MW of natural gas capacity were added between 1996 and 2003, coal appears to be the preferred resource for future development. Twenty-seven new coal facilities totaling just over 15,900 MW are planned in the Western States, 17 in the Southwest Region and 10 in the Northwest Region. Twenty-three of the new plants will use PCC, three will use Circulation Fluidized Bed Combustion technology and one plant is proposed to use Integrated Coal Gasification technology.
- **Hydropower Dominates the Pacific Northwest:** Hydroelectric generation is a significant source of electrical power for the Pacific Northwest. While hydropower does not cause air pollution, large-scale hydropower generation affects the flow of rivers and alters riparian ecosystems. The construction and operation of hydroelectric dams directly impact the diminishing fish populations of chinook, sockeye and coho salmon, and steelhead.
- **Increase in Dam Decommissioning:** Dam decommissioning is increasing in the U.S. Over the past decade 177 dams have been removed, including 26 dams in 1999. Decommissioning of older facilities can be more cost effective than upgrading to meet current environmental standards. More than 500 Federal Energy Regulatory Commission (FERC) licenses will expire in the next decade.
- **Water Use Is a Key Environmental Issue for Power Generation in the West:** Dedicated coal plants (those owned by California utilities) and natural gas plants use approximately 7,000 to 28,000 acre feet of water per year, most of which comes from fresh water sources. Water use for power plant cooling has a significant impact on water use in the Southwest. The five-year drought caused some projects to be denied because of their dependence on local water sources and caused existing facilities to change their operations to ensure an adequate supply of water. With the demand to build additional facilities in response to the energy shortage of 2000-2001; and the fact that coal-fired plants are a dominant source of electrical power in the Southwest, pressure on water resources is expected to increase.
- **Renewable Development Is Affecting the Resource Mix:** The development and use of renewable energy sources (wind, biomass and geothermal) for power generation could affect the amount of imported power generation and the generation mix. In Los Angeles, an area dependent on imported energy, the city committed to expand its use of renewable energy from 3 percent to 20 percent by 2017. In addition, the Los Angeles Department of Water and Power (LADWP) has withdrawn its support of the proposed expansion of the Intermountain coal power plant to increase its use of renewable energy sources.

## Report Organization

This report includes the following three sections:

- Section I presents the questions considered in this report and the report findings.
- Section II describes the electricity mix for the Northwest and Southwest Regions. This section provides applicable environmental laws with a particular emphasis on air quality regulations. Technologies and pollution controls are also presented.
- Section III presents the generation characteristics for each fuel type. This section focuses on coal, which is the predominant energy source in the West, and on hydro-power, which is a significant source of energy from the Pacific Northwest. Information is also presented for natural gas, nuclear, and renewables.

In addition, there are four attachments to this report:

- Attachment A: Environmental Laws and Trends
- Attachment B: 1996 to 2003 Generation of Out-of-State Coal-Based Power Plants that Export to California
- Attachment C: Air Quality Information
- Attachment D: Threatened and Endangered Species by Region

# CHAPTER 2: THE WESTERN REGIONAL RESOURCE MIX

## Electric Generation in the Northwest and Southwest Regions

In 2003, California imported approximately 61,811 gigawatt hours (GWh) of electricity from out-of-state sources; 36 percent was from the Northwest Region and 64 percent was from the Southwest Region.[1] The imports represent approximately 31 percent of California's total energy supply in 2003. The fuel types that characterize these imports from the western U.S., Canada, and Mexico are largely a function of where fuels occur as natural resources. As shown in Figure 2-1, the easternmost states within the Northwest Region predominantly rely on coal-based electricity generation.

Table 2-1 summarizes the energy generation and capacity available within each state and its fuel type. States dominated by hydroelectric generation are located in the Northwest. The greatest percentage of natural gas-based electricity generation is in Nevada, while the largest nuclear facility in the West is located in Arizona. However, for both of these states, gas and nuclear power are not predominant energy sources.

Within Mexico, electricity generation is predominately petroleum-based.[2] In 2000, Mexico generated 54% of its electricity from petroleum-based power plants. However, by 2010, 50% of the country's electricity is projected to come from natural gas-based plants, while petroleum-based plants would only provide 28 percent of its electricity. Western Canada generates most of its electricity from hydropower. Figure 2-1 provides the comparison of fuel types used to generate electricity for the western states, the U.S., and the bordering countries of Mexico and Canada.

Table 2-2 illustrates trends in generation from 1996 to 2003. The table shows a significant amount of gas-fired electrical capacity added during this seven-year period. In 2003, of the total 7,596 MW of added capacity from natural gas plants, 4,836 MW (64 percent) were added in California and 2,760 MW (36 percent) were added in the other western states. In comparison, California did not add any new coal-generated capacity during this period, while approximately 80 MW of capacity were added in other western states.

## Table 2-1 State Electricity Capacity and Generation by Fuel Source (2002)

| State | Fuel Type | | | | | | | | | | | | Total Capacity/Generation | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Coal | | Hydropower | | Natural Gas | | Nuclear | | Renewables | | Other | | | |
| | MW | MWh | MW | MWh | MW | MWh | MW | MWh | MW | MWh | MW | MWh | MW | MWh |
| Arizona | 5,404 | 38,226,631 | 2,919 | 7,551,144 | 4,198 | 17,293,015 | 3,733 | 30,861,911 | 5 | 141,519 | 112 | 57,446 | 16,371 | 94,131,666 |
| California | 352 | 2,327,809 | 14,094 | 30,899,631 | 25,317 | 89,624,044 | 4,324 | 34,352,340 | 5,102 | 23,680,568 | 948 | 3,325,639 | 50,137 | 184,210,031 |
| Colorado | 4,931 | 35,388,251 | 1,206 | 988,743 | 2,370 | 9,028,490 | NA[2] | NA | 47 | 168,840 | 164 | 23,180 | 8,718 | 45,597,504 |
| Idaho | 16 | 90,673 | 2,665 | 8,769,321 | 481 | 328,988 | NA | NA | 81 | 508,303 | 20 | 89,648 | 3,263 | 9,786,933 |
| Montana | 2,296 | 15,337,829 | 2,717 | 9,566,909 | NA | NA | NA | NA | 11 | 63,470 | 90 | 469,659 | 5,114 | 25,437,867 |
| Nevada | 2,658 | 16,413,025 | 1,052 | 2,267,586 | 1,485 | 12,210,660 | NA | NA | 168 | 1,127,283 | 43 | 25,472 | 5,406 | 32,044,026 |
| New Mexico | 3,942 | 26,902,880 | 82 | 264,591 | 1,321 | 3,441,739 | NA | NA | 6 | 19,408 | 25 | 33,089 | 5,376 | 30,661,707 |
| Oregon | 567 | 3,779,684 | 9,089 | 34,413,167 | 1,739 | 7,812,894 | NA | NA | 357 | 1,086,920 | NA | NA | 11,752 | 47,092,665 |
| Utah | 4,562 | 34,487,723 | 254 | 457,732 | 791 | 1,380,181 | NA | NA | 34 | 228,848 | 31 | 53,519 | 5,672 | 36,608,003 |
| Washington | 1,407 | 8,660,805 | 21,778 | 78,162,132 | 1,240 | 4,719,311 | 1,108 | 9,048,475 | 519 | 1,788,385 | 40 | 73,302 | 26,092 | 102,452,410 |
| Wyoming | 5,722 | 41,923,161 | 300 | 583,615 | 177 | 713,080 | NA | NA | 141 | 447,330 | 8 | 40,104 | 6,348 | 43,707,290 |
| **Total** | **31,857** | **223,538,471** | **56,156** | **173,924,571** | **39,119** | **146,552,402** | **9,165** | **74,262,726** | **6,471** | **29,260,874** | **1,481** | **4,191,058** | **144,249** | **651,730,102** |

[1] "Other" includes dual-fired fuel sources, other gases, and petroleum.
[2] NA indicates that data is not applicable or was not provided.
Source: U. S. Department of Energy, Energy Information Administration, February 2004, State Electricity Profiles, http://www.eia.doe.gov/cneaf/electricity/st_profiles/e_profiles_sum.html, (May 16, 2005).

**Table 2-2 New Capacity Development in WECC and California (MW)**

| Year | Coal | | Hydropower | | Natural Gas | | Nuclear | | Renewables | | Other[1] | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | WECC | CA | WECC | CA | WECC | CA | WECC | CA | WECC | CA | WECC | CA |
| 1996 | 0 | 0 | 0 | 33 | 988 | 286 | 0 | 0 | 0 | 83 | 42 | 0 |
| 1997 | 0 | 0 | 58 | 0 | 248 | 323 | 0 | 0 | 0 | 23 | 0 | 12 |
| 1998 | 0 | 0 | 2 | 0 | 336 | 0 | 0 | 0 | 94 | 9 | 0 | 0 |
| 1999 | 0 | 0 | 0 | 3 | 547 | 0 | 0 | 0 | 98 | 138 | 0 | 13 |
| 2000 | 0 | 0 | 3 | 0 | 762 | 4 | 0 | 0 | 27 | 67 | 0 | 18 |
| 2001 | 0 | 0 | 0 | 40 | 3,800 | 2,572 | 0 | 0 | 387 | 68 | 0 | 8 |
| 2002 | 0 | 0 | 0 | 2 | 6,808 | 3,164 | 0 | 0 | 129 | 115 | 27 | 51 |
| 2003 | 80 | 0 | 0 | 0 | 7,596 | 4,836 | 0 | 0 | 389 | 194 | 18 | 0 |

Source: EIA-860 Database for 2003: http://www.eia.doe.gov/cneaf/electricity/page/eia860.html.
“[1]Other” includes: Distillate fuel oil, other gas, miscellaneous technologies, petroleum coke, wood waste solids

## Technologies and Pollution Controls

Table 2-3 presents a summary of technologies and pollution controls for the five fuel sources discussed in this report. The table identifies pollution controls that reduce the amount of pollution generated by power plants and new technologies that are either in place or under development to address further reductions. Information on the environmental consequences potentially caused by these plants and typical mitigation to reduce those consequences is presented below and discussed more fully in the next section.

The majority of the existing and proposed coal-fired plants use the **Pulverized Coal Combustion** technology. As noted in Table 2-3, this technology is used by 90 percent of existing coal plants. As discussed later in this report, most proposed facilities will use this same technology. Proposed facilities plan to implement pollution control measures to reduce air, water, and biological effects.

**Advanced fossil fuel power technologies** have lower (in some cases much lower) emission levels than traditional coal- and natural-gas fired technologies. A comparison of estimated emissions from these technologies versus current baseline emission levels is provided in Table 2-4.

The emission factors for a specific facility depend upon actual coal composition, the level of emission control, and the facility’s operating profile. Emission factors for older existing technologies such as natural gas fired boilers and older coal-fired facilities would be higher than the comparative technologies listed in Table 2-4.

Table 2-4 shows that advanced coal-fired power technologies can significantly lower the emission levels for coal power. In particular, **Integrated Gasification Combined Cycle** (IGCC) systems can reduce pollutants significantly more than conventional coal technologies. However, even these “clean coal” technologies emit more NOx, $SO_2$ and $CO_2$ than available conventional natural gas fired power technologies. Wyoming is currently considering the development of its coal resources through a coal-to-liquid facility, which will be powered by an IGCC facility. This facility is expected to be online between 2008 and 2010 and would serve customers in Colorado, Utah, and Wyoming.[3]

## Table 2-3 Technologies and Pollution Controls by Fuel Type

| Fuel Type | Technologies | Pollution Controls |
|---|---|---|
| **Coal** | **Pulverized Coal Combustion (PCC) -** Accounts for 90 percent of coal-fired capacity. Coal is ground into powder and burned to produce steam; steam drives turbines and generates electricity.<br>**Circulation Fluidized Bed Combustion -** Coal is burned in a mixture of heated particles that are suspended in flowing air or gas. The mixture acts as a boiling liquid and burns coal at a lower temperature than PCC.<br>**Integrated Coal Gasification Combined Cycle –** Exposes coal to steam and oxygen, which produces carbon monoxide and hydrogen fuel gas. Combustion of the fuel gas drives the gas turbine, from which exhaust heat generates steam for a steam turbine.<br>**Pressurized PCC –** New technology that uses pressurized flue gases expanded through a gas turbine to drive the turbine's compressor and generate electricity.<br>**Supercritical and Ultrasupercritical** – New technology that uses a single phase fluid within a once-through boiler; does not require separation of steam from water. | Better technologies are under development as noted under the technologies column to reduce pollution associated with coal-fired plants. For instance:<br>• Fluidized Bed Combustion results in lowest NOx and SOx emissions when limestone is added to the fuel;<br>• Coal gasification produces less solid waste and lower emissions of SOx, NOx, mercury, and possibly less $CO_2$; and<br>• New technologies such as the Supercritical and Ultrasupercritical technologies are more efficient than PCC and require less fuel per unit of electricity generated. |
| **Hydropower** | Uses **energy of falling water** to generate electricity. The flow and fall of water determines the potential for power production. | Pollution controls normally apply to secondary containment of oil-filled equipment and water regulation and control as influenced by project operations to avoid impacts on biological species and habitat. These include:<br>▪ Fish screens to prevent entrainment and ladders to support fish migration;<br>▪ Instream flow releases; and<br>▪ Multi-level intake structures for deep reservoirs to control water temperature and quality of instream releases. |
| **Natural Gas** | **Steam Generator Units** burn natural gas in a boiler to heat water and produce steam, which then drives a steam turbine generator.<br>**Simple Cycle Units** burn natural gas in a combustion turbine generator.<br>**Combined Cycle Units** burn natural gas in a combustion turbine generator and then harness the exhaust heat to create steam for a steam turbine generator. Preferred for low cost, fuel efficiency, and environmental performance. | • Filtration System Filters;<br>• Chemical for prevention of biological growth and corrosion;<br>• Electrically powered and magnetic water conditioning units;<br>• Cooling tower equipment materials; and<br>• Pretreatment systems. |

| Fuel Type | Technologies | Pollution Controls |
|---|---|---|
| **Nuclear** | **Nuclear fission** used to heat water and create steam for a steam turbine generator. | Radioactive Waste Treatment;<br>• Purification systems for gases and coolants;<br>• Storage tanks to allow short-half-life radioactive materials to decay down to safer levels, leaving small quantities of long-half-life radionuclides to be released under permits;<br>• Sumps and drains that collect liquid for processing, and eventual reuse or discharge;<br>• Segregation and processing of low-level radioactive solid waste for compaction and shipment to off-site waste management vendors;<br>• Storage of spent fuel in storage pools or dry casks or vaults; and<br>• Isolation of radioactive water from non-radioactive water through separate systems.<br>Non-radioactive Waste Treatment;<br>• Processing of gaseous and liquid wastes in purification and wastewater treatment plants onsite prior to discharge;<br>• Collection of solid wastes for packaging and disposal offsite;<br>• Treatment of liquid wastes in compliance with the NPDES; and<br>• Storage and disposal of solid wastes in compliance with Nuclear Regulatory Commission regulations and the Resource Conservation and Recovery Act. |
| **Renewable Energy Resources** | **Wind** – A wind turbine converts the energy from wind into electricity.<br>**Geothermal Power** – Geothermal Energy (heat from the earth).<br>• Steam – steam expanded through a turbine to generate electricity; more cost-effective when resource temperature is above 175°F; and<br>• Binary – for reservoirs that are not hot enough to flash; closed loop system that pumps geothermal water through one side of a heat exchanger where its thermal energy is transferred to a second liquid. The working liquid boils to vapor, which expands and powers the turbine generator.<br>**Biomass Energy** uses organic materials such as agricultural and forest residues, animal waste, and landfill gas to produce electricity. | **Wind** power plants emit no pollutants and use no water. Thus, there are no air and water pollution controls. However, there are bird and bat effects that are described later in this report.<br>**Geothermal plants**:<br>• No discharge to water sources;<br>• Lined sumps used to hold produced fluids and allowed to dry out; and<br>• Sump materials are continually tested, and, if hazardous, the material is sent to a hazardous material disposal site.<br>**Biomass** power plants may utilize closed-loop cooling to avoid thermal discharge and the discharge of pollutants within the boiler and cooling systems. |

Sources: Coal: World Coal Institute, 2005a and b. Natural Gas: Natural Gas Organization, 2005; California Energy Commission (CEC), 2005a. Nuclear: SCE, 2002; Energy Northwest, 2005; NRC, 1996a. Hydropower: Aspen 2004 and 2005; Reeves, 2003.

According to the U.S. Department of Energy, $CO_2$ emissions from coal-fired electric generation account for nearly 80 percent of total $CO_2$ emissions produced by the generation of electricity in the U.S.[4] Emissions of $CO_2$ from coal in 1999 were approximately 1,788 million metric tons. Coal has the highest carbon intensity among fossil fuels, resulting in the highest $CO_2$ output rate per kilowatt per hour. Electricity generators constitute 37 percent of the total $CO_2$ emissions in the U.S. and are a major contributor to greenhouse gases and potential **climate change effects**. Nearly 80 percent of total $CO_2$ emissions produced from U.S. electric generators are attributed to coal-based power plants.[4]

### Table 2-4 Fossil Fuel Power Technology Emission Factors (lbs/MWh, $CO_2$ in tons/MWh)

| **Technology** | | **NOx** | **PM10** | **$SO_2$** | **$CO_2$** |
|---|---|---|---|---|---|
| **Natural Gas Combined-Cycle Turbine Systems** | | | | | |
| GE F-Frame (500 MW, 2 gas turbine w/1 steam turbine)[1] | | 0.054 | 0.036 | 0.0052 | 0.43 |
| Newer GE H System (400 MW, single-shaft turbine)[2] | | 0.046 | 0.025 | 0.0045 | 0.38 |
| **Conventional and Advanced Coal Technologies** | | | | | |
| PCC | Baseline Coal-Fired Boiler (Roundup Power Project, MT) | 0.672 | 0.144 | 1.150 | 1.01 |
| IGCC | Oxygen-Blown Destec First-of-Kind (543 MW) | 0.21 | <0.018 | 0.48 | 0.85 |
| | Oxygen-Blown Destec Intermediate (400 MW) | 0.182 | 0.015 | 0.13 | 0.75 |
| | Transport Reactor | 0.16 | 0.014 | 0.12 | 0.69 |
| | Oxygen-Blown Destec Advanced (500 MW) | 0.167 | 0.014 | 0.12 | 0.70 |
| Fluidized Gas | PC Boiler – Supercritical PC with FGD | 1.35 | 0.08 | 1.47 | 0.87 |
| | PC Boiler – Ultra-Supercritical PC with FGD | 1.35 | 0.08 | 1.42 | 0.84 |
| Fluidized Bed | CPFBC, Circulating Bed, Second Generation | 0.725 | 0.006 | 1.67 | 0.75 |

Sources: [1] Sacramento Municipal Utility District, 2001. Application for Certification, Volumes 1 and 2 (01-AFC-19). Submitted to the California Energy Commission on September 13, 2001. Docket date September 13, 2001.
[2] Inland Empire Energy Center LLC, 2005, Amendment No. 1. March 11, 2005.
[3] Northwest Power and Conservation Council, *The Fifth Northwest Electric Power and Conservation Plan, Appendix I, May 2005. http://www.nwppc.org/energy/powerplan/plan/Default.htm*
[4] U.S. Department of Energy. *Market-Based Advanced Coal Power Systems. May 1999. http://www.fe.doe.gov/programs/powersystems/publications/MarketBasedPowerSystems/Market-Based_Advanced_Coal_Power_Systems.html*

The California Energy Commission has estimated the $CO_2$ emissions associated with coal-fired electricity imports generated by out-of-state power plants owned by California utilities.[5] For 1999, $CO_2$ emissions from these plants were approximately 33.5 million metric tons.

It may be possible to reduce atmospheric concentrations of $CO_2$ by applying **carbon sequestration** technologies currently in the research and development stages. These technologies include the following:[6]

- Geological storage. $CO_2$ is compressed into a dense state and piped into natural geological 'reservoirs' (e.g., depleted oil and gas reservoirs);
- Saline Aquifers. $CO_2$ is stored in deep saline water-saturated reservoir rocks;
- Mineral Carbonation. $CO_2$ reacts with naturally-occurring substances to create a product similar to carbonate minerals; and
- Enhanced Coalbed Methane. $CO_2$ is stored in unmineable coal seams in order to improve production of coalbed methane.

$CO_2$ capture and storage is currently used in the energy industry as a tertiary oil recovery process in which $CO_2$ is injected into oil fields. Kinder Morgan owns much of the existing $CO_2$ pipeline infrastructure and is arguably the most experienced $CO_2$ enhanced oil recovery company.[7]

## Applicable Environmental Laws

Environmental laws enacted for the western states mandate the protection of water, biological resources, and air. A list of regulations for water and biological resources by state is provided in Attachment A. For energy facility siting some states have adopted state environmental policies (Washington, Oregon, and Montana) while others have not (Arizona). States without specific state environmental review policies rely on the National Environmental Policy Act. Further, most states implement federal air quality regulations, with few if any modifications. However, the exact interpretation and implementation of regulations varies from jurisdiction to jurisdiction. Additionally, some western states or local jurisdictions have local regulations that can also affect power plant permitting and operation.

Another key process for regulating energy facilities is the FERC's licensing, relicensing, and decommissioning processes. Hydropower relicensing issues are discussed in Section III.

Currently within the defined out-of-state area (ten western states, western Canada and northern Mexico) there are at least 29 jurisdictions (local, state and federal), not including Native American tribal jurisdictions, that may have complete or limited permitting and enforcement authority for power plants.

### *Air Quality Regulations*

With regard to air quality, the U.S. Environmental Protection Agency (U.S. EPA) retains oversight for implementation of all federal regulations and authority to enforce those regulations. Additionally, the U.S. EPA has completed agreements with Canada and Mexico to address border pollution. The most pertinent air quality regulations applicable to power plant permitting, operation, and future emissions follow:

**New Source Review (NSR)/Prevention of Significant Deterioration (PSD)**
All large fossil fuel fired and biomass fuel-fired facilities would be subject either NSR or PSD permitting regulations. NSR and PSD permitting are required in non-attainment and attainment areas, respectively, for new and modified facilities with the potential to emit pollutants above designated levels. Small fuel-fired facilities may not trigger these permitting requirements, depending on the attainment status and the variations in state or local jurisdiction rules. This rule requires Best Available Control Technology for attainment areas and Low Achievable Emission Rate technology to be applied in non-attainment areas. PSD permitting includes modeling assessments to prove that proposed projects will not cause significant air quality deterioration.

**Title IV Acid Rain Rule**
The goal of the Title IV Acid Rain Rule is to reduce fossil fuel-fired power plant $SO_2$ and NOx emissions by ten million tons and two million tons, respectively, from 1980 levels. The rule requires facilities to either meet yearly $SO_2$ emission allowances, where facilities can add controls, or to buy extra trading credits from other facilities to increase their allowance for annual $SO_2$ emissions. This rule also provides for a nationwide $SO_2$ emission cap of 8.95 million tons. The NOx reductions from coal-fired boilers are met through either meeting a specified emission limit for a single boiler, or having two or more boilers meet an average emission limit. The NOx program does not cap emissions or utilize an allowance trading system. The overall western states' NOx and SOx emission profile is considerably lower than that for the rest of the nation; the vast majority of the emission reductions occurring due to this regulation will occur outside the western states.

**New Source Performance Standards (NSPS)**
There are several NSPS that currently apply to power generating technologies. The NSPS provide for emission standards and monitoring requirements for specified emission source categories. For the power industry 40 CFR Part 60 Subparts D and D (a) regulate power boilers and Subpart GG regulates Stationary Gas Turbines. In general, the BACT determinations required under the NSR will require emission limitations that are lower than the NSPS standards.

**Regional Haze Rule**
The Regional Haze Rule of 1999 was enacted to improve visibility or visual air quality in the 156 national park and wilderness areas, also known as Class 1 Areas, across the country. 79 are located within the western states (108 including California). This rule requires states to provide regional haze plans by December 2007 that establish goals and provide long-term strategies for reducing emissions of pollutants that impair visibility. Power plants, particularly coal-fired power plants, are a source of concern; long-term emission reduction strategies could include strategies to reduce NOx, SOx, and particulate emissions from power plants.

## *Recently Enacted and Proposed Regulations for Air Quality*

**Clean Air Interstate Rule (CAIR)**

The CAIR was signed March 2005. It is the goal of the CAIR to create significant reductions in $SO_2$ and NOx emissions in the eastern 28 states and the District of Columbia. This rule creates a cap and trade system aimed at achieving emission reduction goals, primarily from the power sector. The reduction goals include:[8]

- In 2010, CAIR will reduce $SO_2$ emissions by 4.3 million tons – 45 percent lower than 2003 levels – across states covered by the rule. By 2015, CAIR will reduce $SO_2$ emissions by 5.4 million tons, or 57 percent, from 2003 levels in these states. At full implementation, CAIR will reduce power plant $SO_2$ emissions in affected states to just 2.5 million tons, 73 percent below 2003 emission levels.
- CAIR will also achieve significant NOx reductions in states covered by the rule. In 2009, CAIR will reduce NOx emissions by 1.7 million tons or 53 percent from 2003 levels. In 2015, CAIR will reduce power plant NOx emissions by 2 million tons, achieving a regional emissions level of 1.3 million tons, a 61 percent reduction from 2003 levels.

Western states are not affected by this rule. The CAIR was recommended by the National Academy of Sciences and environmental groups such as Environmental Defense.[9] With passage of this rule further regulation of western states power plant emissions, beyond existing Clean Air Act requirements, is uncertain.

States also have to provide revisions to their State Implementations Plans (SIPs) to address interstate transport of pollution as required after the promulgation of a new ambient air quality standard – in this case the new $PM_{2.5}$ and 8-hour ozone standards. These SIP revisions assess interstate transport effects on downwind non-attainment areas in adjacent states and provide strategies (which may include proposed emission reductions at power plants) to remedy interstate transport issues. Currently, there are few western states outside of California that are likely to be found to significantly contribute to $PM_{2.5}$ and 8-hour ozone non-attainment areas through downwind transport. However, this issue may be complicated pending likely revisions (i.e., reductions) to the $PM_{10}$, $PM_{2.5}$, and 8-hour ozone Ambient Air Quality Standards (AAQS) within the next two to three years.

**Clean Air Mercury Rule**

U.S. EPA published the final Clean Air Mercury Rule on May 18, 2005.[10] In summary, this rule imposes a state-by-state emission cap for coal-fired electrical generation sources in 2010 (that will be reduced again by 60 percent in 2018); and imposes a NSPS for new coal-fired sources constructed or reconstructed after January 30, 2004. The emission cap requirement is designed to allow interstate mercury credit trading similar to that allowed by the Clean Air Act Title IV Acid Rain rule. This rule will reduce the current nationwide coal-fired power plant mercury emission estimate, 48 tons nationally, by approximately 70 percent. The 2010 emission cap in the Clean Air Mercury rule allows emissions of approximately 4.5 tons of mercury from coal-fired power plants in the western states (38 tons nationally) and the rule lowers the emission cap to approximately 1.8 tons (15 tons nationally) in 2018.

**Clear Skies Act**

The Clear Skies Act of 2003 and proposed 2005 Clear Skies legislation would put in a market-based cap and trade regulation to reduce NOx, $SO_2$ and mercury emissions from power plants. However, the Clean Skies Act would also weaken existing Clean Air Act provisions such as NSR provisions for major modifications of existing facilities. Some environmental groups argue that the Clean Skies Act would actually increase emissions above those emissions from proper implementation and enforcement of existing Clean Air Act law.[11]

The Clear Skies Act projects reduction of nationwide electric $SO_2$ emissions by 73 percent from year 2000 levels, NOx emissions by 67 percent from year 2000 levels, and mercury emissions by 69 percent from year 1999 levels. The mercury emission limitations were enacted under provisions of the Clean Air Mercury Rule. The U.S. EPA identified the following emission benefits to the western states by 2020 under the Clear Skies Act: (see Table 2-5):

**Table 2-5 Proposed Clear Skies Act Emission Reductions by State**

| State | $SO_2$ | NOx | Mercury |
|---|---|---|---|
| Arizona | Unchanged | 63% Reduction | 69% Reduction |
| California | Unchanged | 6% Reduction | Unchanged |
| Colorado | Unchanged | 32% Reduction | 37% Reduction |
| Idaho | Unchanged | 24% Reduction | Unchanged |
| Montana | 4% Reduction | 19% Reduction | 11% Reduction |
| Nevada | 19% Reduction | 39% Reduction | 36% Reduction |
| New Mexico | 13% Reduction | 57% Reduction | 28% Reduction |
| Oregon | Unchanged | Unchanged | Unchanged |
| Utah | Unchanged | 13% Reduction | Unchanged |
| Washington | 93% Reduction | 73% Reduction | 58% Reduction |
| Wyoming | 2% Reduction | 68% Reduction | 43% Reduction |

Source: U.S. EPA, Clear Skies Act – Where You Live Website, http://www.epa.gov/air/clearskies/where.html, Accessed May 2005.
Note: Reductions are from 2020 base year emissions considering existing regulations.

However, with passage of the CAIR and the Clear Air Mercury Rule it is unclear whether additional power plant emission reductions will be sought from the western states as part of the proposed Clear Skies legislation.

## *Water Quality Regulations*

**National Pollutant Discharge Elimination System (NPDES)**

Power plants are required to comply with Section 402 of the Clean Water Act, under which they must seek permits for any point source[12] pollutant discharge that occurs during construction or operation activities. Under Section 402, Part (l) (2), certain oil, gas, and mining operations are exempt from NPDES requirements.[13] As this exemption has continued to raise questions from industry and environmental stakeholders regarding the specific types of activities that are exempt, the U.S. EPA has chosen to further examine the limitations of Section 402, Part (l)(2).[14] Although oil and gas construction activities that disturb between one to five acres were subject to NPDES permit requirements beginning March 10, 2005, the U.S. EPA chose to extend the deadline for obtaining NPDES permits until June 12, 2006. During this postponement, the U.S. EPA plans to further examine Section 402(l) (2) and to continue to evaluate practices and methods that operators may use to control storm water discharges from affected sites.[14]

# CHAPTER 3: ENVIRONMENTAL EFFECTS OF POWER IMPORTS BY FUEL TYPE

## Coal Resources

### *Overview of Coal Resources*

Coal is the primary fuel source for electric generation within the U.S. In 2003, 51 percent of the nation's electricity originated from coal-fired power plants. Coal-based electricity is expected to decline only slightly, to 50 percent, in 2025.[15] Additionally, 92 percent of all coal consumed in the U.S. in 2003 was used for electricity generation.[16] This section describes key issues associated with coal-generated electricity and provides specific information on the approximately 4,744 MW of electricity supplied to California by out-of-state coal plants. Twenty-seven coal-based power plants totaling just over 15,900 MW are identified in the western states that are under construction, have received environmental permits, or that are proposed for permitting and construction. Given the continuing uncertainties with power plant financing and project development, these numbers are subject to change. Please consult the following link to the Energy Commission's Electricity Analysis Office's (EAO) database of proposed out of state power plants for the most recent information.  The EAO will also produce a summary of proposed generation in its assessment of in and out of state generation resources, scheduled for release as an Energy Report supporting document on July 11, 2005. http://www.energy.ca.gov/electricity/wscc_proposed_generation.html

#### Northwest Region

The Northwest Region (excluding Canada) generated approximately 69,792,150 MWh of electricity from coal-based power plants in 2002.[17] Wyoming produced the greatest percentage of its electricity from coal (96 percent), followed by Montana, Oregon, Washington, and Idaho, respectively (see Figure 2-1).

Ten coal-based power plants totaling 6,212.5 MW are under construction, have received permits, or are proposed (See Table 3-1). Wyoming has either proposed or is planning the construction of three additional coal-based power plants, two of which have been issued construction permits. Two new plants have also been proposed in Idaho, once of which would use Integrated Coal Gasification technology. Montana has begun construction of two new plants (Hardin and Thompson River, PCC technologies) with three additional plants proposed.[18] With the exception of one circulating fluidized bed combustion plant proposed in Montana and the coal gasification facility proposed in Idaho, the remaining proposed coal-based power plants in the Northwest Region would utilize PCC technology.

There is also a proposal for a four-state 1,300 mile electrical line, called the Frontier Line, which would transmit electricity generated from new proposed coal plants in the western states. The Frontier Line has received support from the Governors of California, Wyoming, Utah, and Nevada.[19] The Frontier Line is proposed for construction over the next five years and is planned to “deliver renewable and conventional energy resources generated from wind and clean coal.”[20]

Canada is a major coal producer and consumer. Coal is a key resource and is exported to Asia, Europe, U.S., and Latin America.[21] Coal-generated energy constitutes about 14 percent of the electricity generated in Canada.[22] British Columbia’s electricity comes primarily from hydropower facilities, while Alberta’s power generation includes coal-fired plants. Additional demand for electricity is expected in western Canada. Two 500-MW coal-fired generation units are proposed in Alberta. The first unit is expected at the end of 2005 and the second at the end of 2006. While there are plans to build additional coal-fired plants in Canada, some of the Canadian provinces are phasing out the use of coal. For example, Ontario plans to shut down all of its province coal-fired plants by 2007.[23]

**Southwest Region**

The Southwest Region (excluding Mexico) generated approximately 151,418,510 MWh of electricity from coal-based power plants in 2002.[24] Utah produces the greatest percentage of its electricity from coal (i.e., 94 percent), followed by New Mexico, Colorado, Nevada, and Arizona, respectively (see Figure 2-1).[25]

Twenty-seven coal-based power plants totaling 9,720 MW are under construction, have received permits, or are proposed. Utah has proposed construction of four new coal-based power plants. Additional coal-based power plants proposed in the Southwest include two in Arizona, four in Colorado, four in Nevada, and three in New Mexico.[18] For example, Sempra Energy, a San Diego-based company, proposes to build Granite Fox Power – a 1,450 MW coal-fired plant in Nevada, which will use Selective Catalytic Reduction.[26,27] The plant is undergoing environmental review and is projected to be operational in 2010. Sempra states that the plant would produce 80 percent less pollution than most coal plants.[26] Two of the proposed power plants in Utah would utilize circulating fluidized bed technology (Bonanza and Sigurd Power Projects). The remaining coal-based power plants proposed in the Southwest Region, including Sempra Energy’s Granite Fox power plant, would utilize PCC technology.

Several proposed facilities involve the expansion of existing power plants. An example is the Intermountain Power Plant, which proposed an additional 950-MW generating unit.[28] However, the Los Angeles Department of Water and Power (LADWP) withdrew its involvement with the proposed expansion in order to invest in renewable energy sources for the city.[26,29] Despite LADWP’s withdrawn support for the expansion, construction on the third generating unit is expected to begin in 2006 and would be completed by spring, 2010.[30]

Mexico generates about 6 percent of its electricity from coal.[31] Mexico has two coal-fired plants, Rio Escondido and Carbon II, which are operated by the state-owned utility Comision Federal de Electricidad (CFE). In addition, CFE recently modified its 2,100-MW Petacalco facility on the Pacific Coast from oil to coal.[22] There are no coal-fired plants in northern Mexico. While no coal plants are located in Baja California, they are located in the vicinity of the Mexico-Texas border, near the Gulf of Mexico.[32]

## Table 3-1 Proposed Coal-Based Power Plants in the Western U.S.

| Name and/or Location | Company | Type of Plant | Capacity (MW) | Status* |
|---|---|---|---|---|
| | | | | ***NORTHWEST REGION*** |
| **Idaho** | | | | |
| Jerome County, Idaho | Sempra Energy | Conventional pulverized coal plant | 600 | Proposed. Coal would be shipped by rail from Wyoming's Powder River Basin. |
| Pocatello, Idaho | Southeast Idaho Energy LLC | Coal gasification plant | 520 | Proposed. Proposed location is on the site of the FMC Superfund site. |
| **Montana** | | | | |
| Roundup Power Project, Roundup, Montana | Bull Mountain Development Company | Conventional pulverized coal plant | 780 | The applicant’s projected schedule is to have Unit 1 in service by March 2006, with Unit 2 in service eight months later. |
| Centennial Power Project, Hardin, Montana | MDU Resources Group, an affiliate of Montana-Dakota Utilities electric utility. | Conventional pulverized coal plant | 160 | Permitted and under construction. |
| Nelson Creek Power Project, Circle, Montana | Great Northern Power Development and Kiewit Mining Group | Circulating Fluidized Bed/Wind | 500 MW coal 60 MW wind | Proposed. The project developer is waiting on the completion of a Western Area Power Administration study of Montana transmission alternatives before deciding whether and where to propose the plant. |
| Otter Creek, Montana | Kennecott, Bechtel, and Wesco | (Unknown) | 3,000 | Proposed. The Otter Creek coal tracts were transferred to the State of Montana by the federal government under the Clinton administration. No air permit application has been submitted. |
| Thompson River, Montana | Thompson River Co-Gen | Conventional pulverized coal plant and wood waste | 12.5 | Under construction. |
| **Wyoming** | | | | |
| Two Elk Power Plant, Wright, Wyoming | Bechtel | Conventional pulverized coal plant | 320 | Permit issued. Two Elk is intended to burn 1.8 million tons per year of low-quality coal from the Black Thunder Mine, one of the largest mines in the Powder River Basin. |
| Wygen II, Gillette, Wyoming | Black Hills Corporation | Conventional pulverized coal plant | 90 | Permits issued. 24-month construction period may begin in August 2005. |
| Powder River Basin | Basin Electric Power Cooperative | (Unknown) | 230 | Applications have not been submitted. Applicant has targeted construction to begin in 2008. |
| | | | | ***SOUTHWEST REGION*** |
| **Arizona** | | | | |

| Name and/or Location | Company | Type of Plant | Capacity (MW) | Status* |
|---|---|---|---|---|
| Springerville 3-4, Springerville, Arizona | Bechtel/Unisource and Salt River Project (SRP) | Conventional pulverized coal plant | 760 | Permits issued. Construction started in November 2003. |
| Hopi Nation Lands, Arizona | Reliant and Hopi Nation | (Unknown) | 1,200 | Proposed but inactive. In March 2002, the Hopi Nation and Reliant announced an agreement to study the prospects for a 1,200 MW coal plant on Hopi Nation lands. There have been no formal permit applications submitted for the project. |
| **Colorado** | | | | |
| Pueblo, Colorado | Xcel Energy | Supercritical pulverized coal plant | 750 | The Colorado PUC has approved the project. The project's air quality permit approval is pending. |
| Lamar, Colorado | City of Lamar | Conversion of existing gas-fired plant to coal | 30 | Proposed and active. A Feasibility Study for the proposed conversion was completed in March 2004. |
| Eastern Colorado | Tri-State Generation and Transmission | Conventional pulverized coal plant | (Unknown) | Early stages of development. No permit applications have been filed with state regulators. |
| Buick Coal and Power Project, Limon, Colorado | Radar Acquisitions Corp. | Conventional pulverized coal plant | 500 | Proposed/active. A feasibility study was conducted in April 2004. |
| **Nevada** | | | | |
| Granite Fox Power Project, Gerlach, Nevada | Sempra Energy | Conventional pulverized coal plant | 1,450 | Proposed. The Bureau of Land Management is currently preparing an EIS for the project. Permit applications anticipated in 2006. |
| White Pine Project, White Pine County, Nevada | LS Power | Conventional pulverized coal plant | 500 - 800 | Proposed. Construction scheduled for 2006. Operation anticipated in 2010. |
| TS Power Plant, Dunphy, Nevada | Newmont Mining Company | Conventional pulverized coal plant | 200 | Proposed. Construction scheduled for 2005. Operation anticipated in mid-2007. |
| Valmy Expansion, Dunphy, Nevada | Sierra Pacific Power | Conventional pulverized coal plant | 250 | Proposed but inactive. |
| **New Mexico** | | | | |
| Mustang Power Project, Grants, New Mexico | Peabody | Conventional pulverized coal plant | 300 | Proposed; permit applications submitted. |
| Desert Rock Energy Facility, near Farmington, (on Navajo Lands) | Steag | Conventional pulverized coal plant | 1,500 | Proposed; permit applications submitted. |
| Chaco Valley Energy Facility, (same site as | BHP Billiton | Conventional pulverized coal plant | 550 | The applicant submitted a permit application to the EPA in March of 2004 for a power plant that would operate if the |

| Name and/or Location | Company | Type of Plant | Capacity (MW) | Status* |
|---|---|---|---|---|
| for the Desert Rock Energy Facility) | | | | Desert Rock Energy Facility (above) is not approved. |
| **Utah** | | | | |
| Intermountain Power Plant 3, Lynndyl, Utah | Intermountain Power Agency (IPA) | Conventional pulverized coal plant | 950 | Utah DEQ's Division of Air Quality issued a Notice of Intent to Approve the project in February 2004. The permit was issued in March, but was appealed by environmental groups in Nov. 2004. |
| Sigurd Power Project, Sevier Valley, Central Utah | Nevco Energy | Circulating fluidized-bed plant | 270 | Environmental interest groups filed an appeal of the project's air quality permit in November 2004. |
| Hunter 4, Castle Dale, Utah | Pacificorp | Conventional pulverized coal plant | 400 | Air permit application has been submitted to the Utah Division of Air Quality. The applicant is proposing to "net out" emissions from the new Unit to reduce emissions from the existing units so that there will be no new net increase of emissions caused by Unit 4. |
| Bonanza Power Project, Bonanza, Utah | Deseret Generation and Transmission | Circulating fluidized-bed plant | 110 | The applicant has submitted a Clean Air Act permit application to the U.S. EPA Region 8 in Denver. |

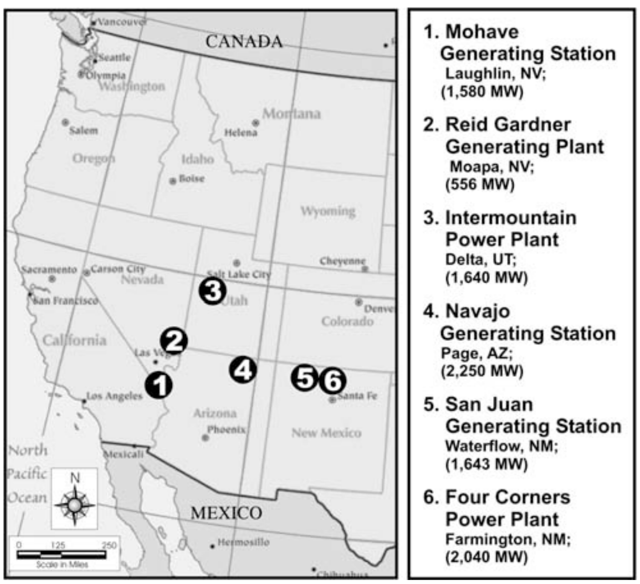
* Note: The sources and status of listed power plant projects is based upon information available on the Internet as of June 17, 2005.

## *Dedicated Coal Energy Resources*

This section provides specific information on the six coal-fired power plants owned by California companies that supply electric power to California. Figure 3-1 provides the location of these plants in relation to each other and to California.

As shown in Table 3-2, two out-of-state plants are operated by California companies (also see Attachment B). The Mohave Generating Station is operated by Southern California Edison and the

**Figure 3-1Dedicated Coal Energy Plants**



## Table 3-2 Out-of-State Coal-Fired Power Plants

| Plant Name | Operating Company | Nameplate Capacity | Cooling System | Generator | Name Plate Capacity | Summer Capacity | Winter Capacity | Energy Source | Ownership | Percent Owned | CA Owned MW |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Arizona** | | | | | | | | | | | |
| Navajo Generating Station | Salt Lake Project Ag. I & P Co. | 2,409 MW | WC | NAV1 | 803.1 | 750 | 750 | BIT | City of Los Angeles DWP | 21.2 | 170 |
| | | | | NAV2 | 803.1 | 750 | 750 | BIT | City of Los Angeles DWP | 21.2 | 170 |
| | | | | NAV3 | 803.1 | 750 | 750 | BIT | City of Los Angeles DWP | 21.2 | 170 |
| **Nevada** | | | | | | | | | | | |
| Reid Gardner Generating Plant | Nevada Power Company | 612 MW | WC | 4 | 270 | 225 | 225 | BIT | California Dept of Water Resources | 67.8 | 183 |
| Mohave Generating Station | Southern California Edison | 1,636 MW | WC | 1 | 818.1 | 790 | 790 | BIT | City of Los Angeles DWP | 20 | 164 |
| | | | | 2 | 818.1 | 790 | 790 | BIT | City of Los Angeles DWP | 20 | 164 |
| | | | | 1 | 818.1 | 780 | 790 | BIT | Southern California Edison Co | 56 | 458 |
| | | | | 2 | 818.1 | 790 | 790 | BIT | Southern California Edison Co | 56 | 458 |
| **New Mexico** | | | | | | | | | | | |
| Four Corners Power Plant | Arizona Public Service Company | 2,070 MW | WC | 4 | 818.1 | 740 | 740 | SUB | Southern California Edison Co | 48 | 393 |
| | | | | 5 | 818.1 | 740 | 740 | SUB | Southern California Edison Co | 48 | 393 |
| San Juan Generating Station | Public Service Company of New Mexico | 1,848 MW | Hybrid (3) and WC | 3 | 555 | 495.4 | 495.4 | SUB | City of Azusa | 6.15 | 34 |
| | | | | 3 | 555 | 495.4 | 495.4 | SUB | City of Colton | 6.15 | 34 |
| | | | | 3 | 555 | 495.4 | 495.4 | SUB | City of Glendale | 4.1 | 23 |
| | | | | 3 | 555 | 495.4 | 495.4 | SUB | City of Banning | 4.1 | 23 |
| | | | | 3 | 555 | 495.4 | 495.4 | SUB | Imperial Irrigation District | 21.3 | 118 |
| | | | | 4 | 555 | 506.1 | 506.1 | SUB | City of Anaheim | 10.04 | 56 |
| | | | | 4 | 555 | 506.1 | 506.1 | SUB | MSR Public Power Agency | 28.71 | 159 |
| **Utah** | | | | | | | | | | | |
| Intermountain Power Plant | LADWP | 1,640 MW | WC | 1 | 820 | 820 | 830 | BIT | Intermountain Power Agency* | 96 | 787 |
| | | | | 2 | 820 | 820 | 830 | BIT | Intermountain Power Agency* | 96 | 787 |
| | | | | | | | | | **Total Out-of-State Coal Resources:** | | **4,744** |

Source: Data taken from the Energy Information Administration website: http://www.eia.doe.gov/cneaf/electricity/page/eia860.html. April 2005.
State Profile data in Energy Information Administration website: http://www.eia.doe.gov/cneaf/electricity/st_profiles/e_profiles_sum.html April 2005.
Notes: WC – Wet Cooling; BIT – anthracite coal or bituminous coal; SUB – subbituminous coal. LADWP or DWP – City of Los Angeles

Department of Water and Power *This plant is 100 percent owned by the IPA. However, California companies own about 96 percent of the generation entitlement share. The percentage shown in the Percent Owned column is the share to California entities.

Intermountain Power Plant is operated by the LADWP. The Mohave Generating Station may close because its operating permit expires late in 2005. In addition, plant operators have been in negotiations with the Hopi and Navajo tribes regarding water and coal leases and environmental groups have raised concerns regarding pollution in the Grand Canyon.[33]

Table 3-2 also includes information on the percent ownership by California firms by plant and by specific generation unit within each power plant. Four of the six power plants shown on the table are owned by more than one California firm. While the Intermountain Power Plant is owned by the Intermountain Power Agency (IPA), the LADWP serves as facility operator. Although the LADWP holds the largest share, other California agencies own shares including the cities of Anaheim, Burbank, Glendale, Riverside, and Pasadena.[34] As noted on the table, there are approximately 4,744 MW of out-of-state coal-generated energy owned by California firms and distributed to California markets.

Table 3-3 shows the highest Average Yearly MWh output for each plant in bold. Inter-mountain Power Plant, which provides 96 percent of its power to California markets, had a significant increase in 1997 and its generation rate increased steadily through 2003. The other plants saw gradual increases or decreases in generation but generally remained at a constant level.

## Table 3-3 Dedicated Coal-Fired Plants - Average Yearly MWh

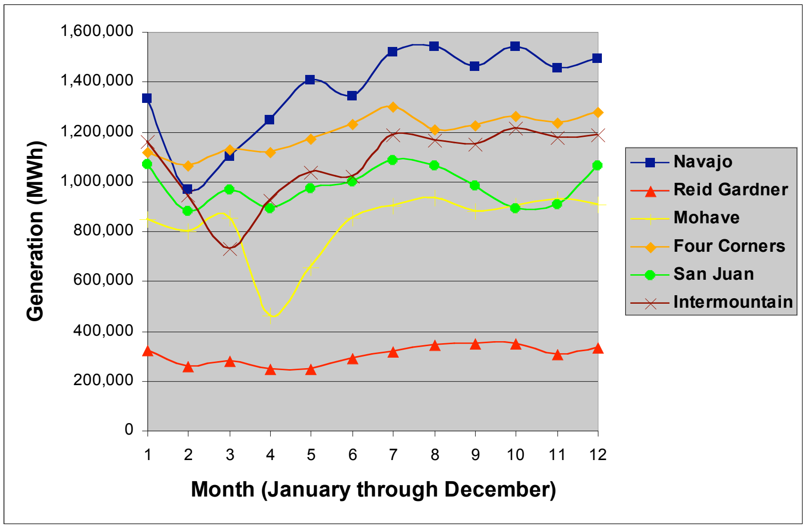
| Year | Navajo | Reid Garner | Mohave | Four Corners | San Juan | Inter-mountain |
|---|---|---|---|---|---|---|
| 1996 | 13,277,675 | 2,364,548 | 9,722,202 | 13,282,499 | 11,403,282 | 10,711,308 |
| 1997 | 15,074,601 | 2,766,466 | 9,648,235 | 13,660,969 | 11,580,416 | 12,762,721 |
| 1998 | 16,462,883 | 4,017,623 | 9,596,626 | 14,503,587 | 11,645,433 | 12,973,101 |
| 1999 | 16,857,616 | 3,671,816 | 9,732,934 | 14,822,999 | 11,641,619 | 13,069,535 |
| 2000 | **18,076,057** | **4,227,897** | **10,700,191** | 14,874,696 | 12,360,462 | 13,176,578 |
| 2001 | 17,366,019 | 3,825,387 | 10,219,861 | 15,009,014 | 11,805,164 | 13,383,601 |
| 2002 | 17,813,020 | 4,174,412 | 10,151,380 | 12,851,339 | **12,368,120** | 13,479,234 |
| 2003 | 16,303,498 | 4,089,401 | 9,673,839 | **15,632,305** | 11,285,455 | **13,554,882** |

Source: MWh data was based on data presented in the Energy Information Administration website: http://www.eia.doe.gov/cneaf/electricity/page/eia860.html. April 2005.

Figure 3-2 presents information on the average monthly MWh generation for out-of-state coal plants from 1996 to 2003. The average monthly data was compared in order to determine if there was a seasonal variation in energy generation. The figure shows a significant decrease for the Intermountain Power Plant from January through March and generation increases from April through July. Generation for all plants decreased from January to February. In the summer months (July and August) there was an increase in electricity generation for all plants, but the increase began in April and leveled out in August. While most of the plants saw a fluctuation in generation from month to month, the Reid Gardner plant had fairly level generation for all months.



**Figure 3-2 Average Monthly Generation from Dedicated Out-of-State Coal-Fired Plants**




## *Air Quality Effects and Key Issues*

### Regional Setting

At least one National Ambient Air Quality Standards (NAAQS) non-attainment area occurs within the Northwest and Southwest Regions for all regulated pollutants except nitrogen dioxide ($NO_2$). The states with non-attainment areas are as follows:[35]

| Pollutant | Western States with Non-Attainment Areas |
|---|---|
| Ozone (1-hr or 8-hr) | Arizona, Colorado, Nevada, New Mexico |
| $PM_{10}$ | Arizona, Colorado, Idaho, Montana, Nevada, New Mexico Oregon, Utah, Washington, Wyoming |
| $PM_{2.5}$ | Montana |
| $SO_2$ | Arizona, Montana, Utah |
| CO | Arizona, Montana, Nevada, Oregon, Utah, Washington |
| Lead | Montana |

Many of these non-attainment areas are small in total area; the vast majority of the total land area for these states is in attainment for each of the criteria pollutants. However, some of the non-attainment areas cover major population center(s) in the affected states (i.e. Phoenix, AZ; Las Vegas, NV; Denver, CO). Additionally, there are other areas formerly in non-attainment that are currently deemed maintenance areas. For comparison, a higher percentage of the total land mass of California is considered in federal ozone and PM non-attainment and California has larger areas of more seriously classified ozone and PM non-attainment areas (i.e., larger areas with higher levels of pollution) than in the Northwest and Southwest Regions noted above.

The U.S. EPA is required to re-evaluate the $PM_{10}$, $PM_{2.5}$, and ozone AAQS during 2006 and 2007. It is likely that one or all of these AAQS may be lowered and the number of areas designated as non-attainment increased substantially as a result.

Similar to California, emissions from power plants in the western states produce a relatively small percentage of the total statewide $PM_{10}$, and $PM_{2.5}$ emissions. However, unlike California, some of the out-of-state power plants contribute large percentages of statewide $NO_2$ and $SO_2$. Table 3-4 provides a comparison of power generation emissions.

**Table 3-4 Power Generation Emissions as Percentage of Statewide Totals (1999)**

| Pollutant | CA | AZ | CO | ID | MT | NV | NM | OR | UT | WA | WY |
|---|---|---|---|---|---|---|---|---|---|---|---|
| $NO_2$ | 1.9% | 22.8% | 24.0% | 0.2% | 24.0% | 26.7% | 27.8% | 4.8% | 31.6% | 7.1% | 37.3% |
| PM10 | 0.3% | 3.1% | 1.8% | 0.02% | 2.1% | 2.0% | 1.5% | 0.2% | 2.2% | 1.5% | 2.6% |
| PM2.5 | 0.8% | 6.4% | 5.1% | 0.02% | 5.4% | 3.3% | 4.7% | 0.3% | 5.1% | 3.7% | 9.0% |
| $SO_2$ | 1.1% | 61.5% | 79.6% | 0.4% | 44.3% | 80.1% | 46.4% | 30.1% | 52.1% | 60.3% | 64.2% |

Source: Derived from information available at http://www.epa.gov/air/data/index.html

It is no coincidence that the states with the highest percentage of power generation $NO_2$ and $SO_2$ emissions are those that use coal as their major energy source. Even states with proportionately smaller amounts of power from coal can have high power generation $SO_2$ emission fractions, such as Oregon and Washington, as long as other major $SO_2$ producing industries are not present (metallic mineral processing or oil production). However, the existing $SO_2$ and ozone non-attainment areas cannot be said to be attributed solely to coal-fired power plants. The $SO_2$ non-attainment areas are mostly attributed to copper smelters, while the ozone non-attainment areas are in major urban areas or downwind of major urban areas where the majority of the local pollution comes from mobile sources.

The major pollutants of concern from power plants are NOx, as an ozone precursor; NOx, SOx, and PM as primary and secondary fine particulate as well as being visibility reducing compounds; and $CO_2$ (and other greenhouse gases such as $N_2O$ and methane expressed as $CO_2$ equivalents) as a greenhouse gas. Effects from visibility-reducing particles on Class 1 Areas are a major concern in many western states. The western states, including California, contain 108 of the 156 Class 1 areas, some of which have significant existing visibility issues. The siting of new power plants – coal or natural gas – in areas that can impact certain Class 1 areas (e.g., the Grand Canyon) would be a difficult challenge without significant reductions in current power technology emission profiles.

**Comparing Emissions from California Generation with Imports from the Western States**

During 2001 through 2003, over two-thirds of the electricity used in California was generated in California: however, the 31 percent generated in the other western states and imported into California is estimated to cause considerably more NOx and $SO_2$ emissions than the in-state power generation. A comparison of the emissions from California generation and the western states' total and imported generation is shown in the following figures and charts. A full set of the generation and emissions charts used in this analysis are in Attachment C. A summary comparison of California generation and imported generation emission statistics is in Table 3-5.

Before comparing emissions from California generation with emissions from imports, it is important to recognize that different data sets and methodologies were used; one for California generation, a second for total generation in the western states, and a third for generation from the dedicated coal plants. California in-state generation emissions are based on the Quarterly Fuels Energy Report (QFER) data reported directly to the Energy Commission by generators. These data were modified and supplemented by data from the 2005 environmental data requests, as described in the Air Quality section of the *2005 Electricity Environmental Performance Report*. Out-of-state emission assessments are based on data from the Energy Information Administration, U.S. Department of Energy (EIA). The differences between these two sources of information can be substantial on a power plant by power plant comparison. The QFER data have less quality control, but more specific data, compared to the EIA data, which have more quality control and less specific data. However, on a larger geographic scale (i.e., inside and outside of the State of California) these two data sources are reasonably compatible.

The proportion of emissions from out of state generation attributed to California imports is based on broad, simplifying assumptions. Using EIA data, Energy Commission staff determined the gross generation in the western states by fuel type and calculated average emission factors for each main fuel type and technology. The amount of generation imported to California for 2001 to 2003 was apportioned by fuel type using the same basic ratio for the resource mix in the western states. The average emission factors were then applied to the apportioned generation by fuel type in order to determine total emissions for the imported power. While this methodology is sufficient for the purposes of this report, it does not capture the differences in unit and power plant-level generation and emissions, nor does it account for actual contracted levels of power between out-of-state generators and California utilities and load serving entities.

## Table 3-5 Comparison of California and Western States Imported Generation (2001 to 2003)

| Location | Percent Generation | NOx Emissions | | $CO_2$ Emissions | | $PM_{10}$ Emissions | |
|---|---|---|---|---|---|---|---|
| | | Emission Factor | Percent Total | Emission Factor | Percent Total | Emission Factor | Percent Total |
| **California** | 69 | 0.366 lb/MWh | 37% | 0.402 t/MWh | 62% | 0.058 lb/MWh | 54% |
| **Western States** | 31 | 1.40 lb/MWh | 63% | 0.554 t/MWh | 38% | 0.111 lb/MWh | 46% |

Table 3-5 shows that imported power NOx emissions per MWh are over 380 percent higher than in-state power NOx emissions; that imported power $CO_2$ emissions per MWh are over 37 percent higher than in-state power $CO_2$ emissions; and that imported power $PM_{10}$ emissions per MWh are over 90 percent higher than in-state power $PM_{10}$ emissions. For $SO_2$, using 1999 emissions data, the total western states $SO_2$ emissions were 400 times higher than the California $SO_2$ emissions. Referencing generation totals, the western states imported power $SO_2$ emissions per MWh is estimated to be on the order of 160 times the in-state power $SO_2$ emissions. In conclusion, energy imported from the western states includes a significant amount of coal-fired power that creates significantly higher emissions per MWh than California power sources.

Of the total western states' generation from 2001 through 2003, approximately 40 percent came from coal-fired power plants, roughly three times more than the western states' natural gas generation total. Traditional coal power boilers have high pollutant emission rates for both criteria pollutants and $CO_2$. The relatively high amount of coal-fired generation in the western states, in comparison with California, causes higher total generation emissions and higher average emissions per MWh of generation. The western states' total power and imported power NOx, $CO_2$ emission statistics for 2001 through 2003 have been estimated; charts showing aggregate emissions by fuel/technology and the comparative emissions in- and out-of-state are shown in Figures 3-3 through 3-10.

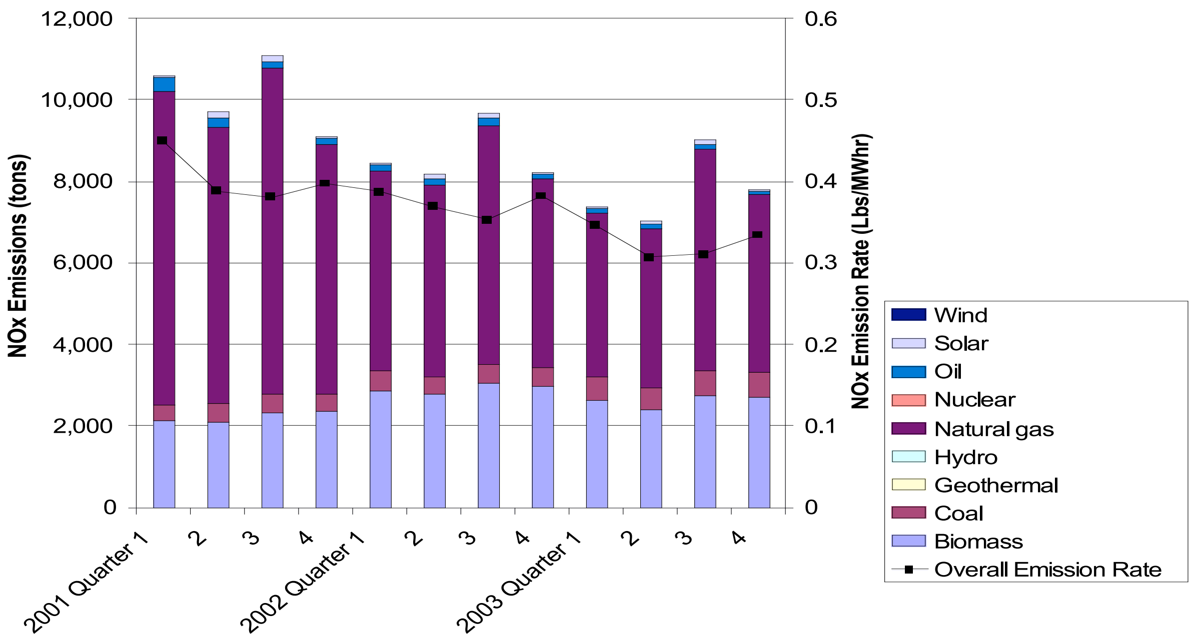
Figures 3-3 through 3-6 show NOx emissions from in-state power, out-of-state power, imported power, and combined power, respectively. In-state NOx emissions (Figure 3-3) are primarily from combustion of natural gas and biomass, and to a much lesser extent, coal. In contrast, the out-of-state NOx emissions shown in Figure 3-4 are overwhelmingly from coal combustion, with a small portion from natural gas combustion. As noted, California's NOx emissions are highly controlled and the NOx emission rate is substantially lower than for out of state gas-fired generation.

Staff calculated imported power NOx emissions (Figure 3-5) by determining the proportion of the out-of-state power that was imported into California and multiplying this percentage by the values presented in Figure 3-4. Therefore, the relative contributions of electricity sources are the same in Figures 3-4 and 3-5 but the NOx emission values differ. Figure 3-6 combines Figures 3-3 and 3-5 and represents the NOx "footprint" for California electric generation for the particular years shown. Coal and natural gas represent about two-thirds and one-third, respectively, of the NOx footprint shown in Figure 3-6.

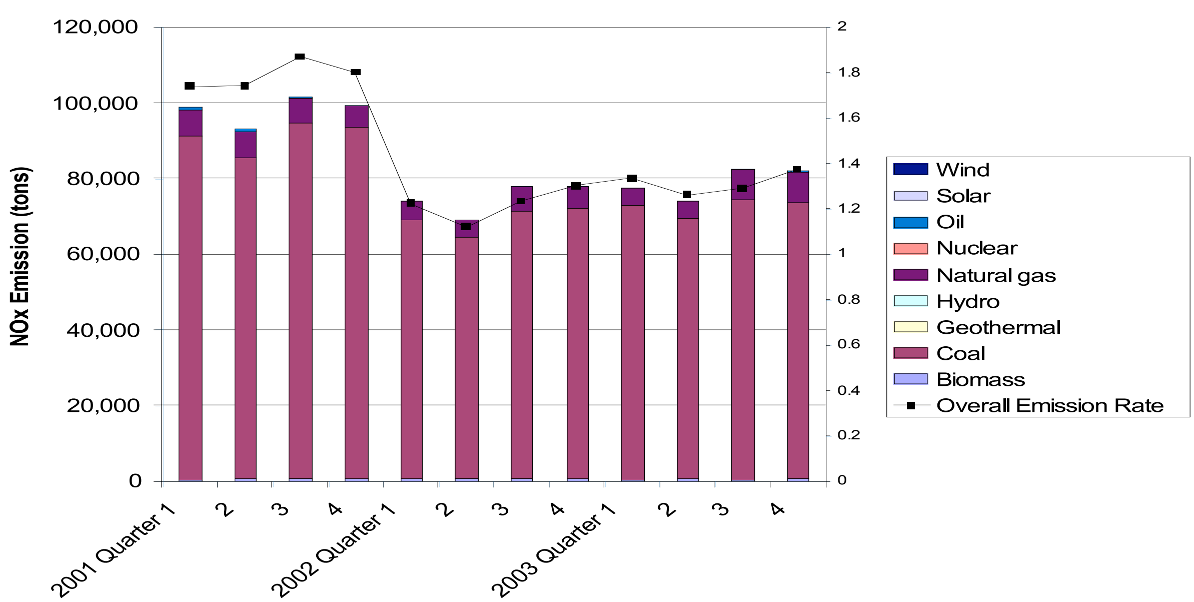
Similarly, Figures 3-7 through 3-10 show $CO_2$ emissions from in-state power, out-of-state power, imported power, and combined power, respectively. The $CO_2$ levels presented in these figures are based on emissions of $CO_2$, methane, and nitric oxide. In-state $CO_2$ emissions shown in Figure 3-7 are almost entirely from combustion of natural gas while out-of-state $CO_2$ emissions shown in Figure 3-8 are almost entirely from coal combustion. The $CO_2$ emission rate for out-of-state generation is quite a bit higher than for in-state generation (about 0.55 tons / MWh versus about 0.4 tons / MWh).

The same methodology as described above was used to determine California's "share" of the out-of-state emissions; this share is shown in Figure 3-9. Figure 3-10 is derived from the combination of Figures 3-7 and 3-9 and shows the total $CO_2$ emission footprint for California. In contrast to the ratios shown in Figure 3-6 for total NOx, natural gas combustion contributes about two-thirds of $CO_2$ emissions, while coal contributes one-third of $CO_2$ emissions. This is due to the large differences in generation levels between natural gas and coal – there is much more gas-fired generation than coal – and to the relative emission rates from natural gas and coal for NOx and $CO_2$. It also highlights the fact that $CO_2$ cannot be controlled as NOx is.

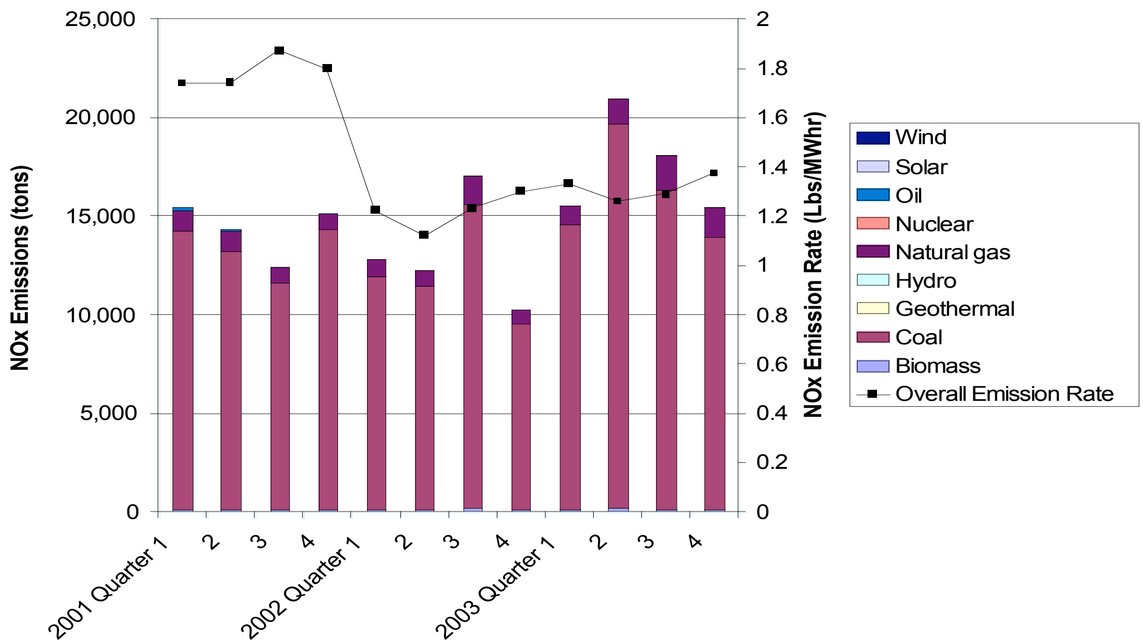
## Figure 3-3 In-State Power $NO_x$ Emissions



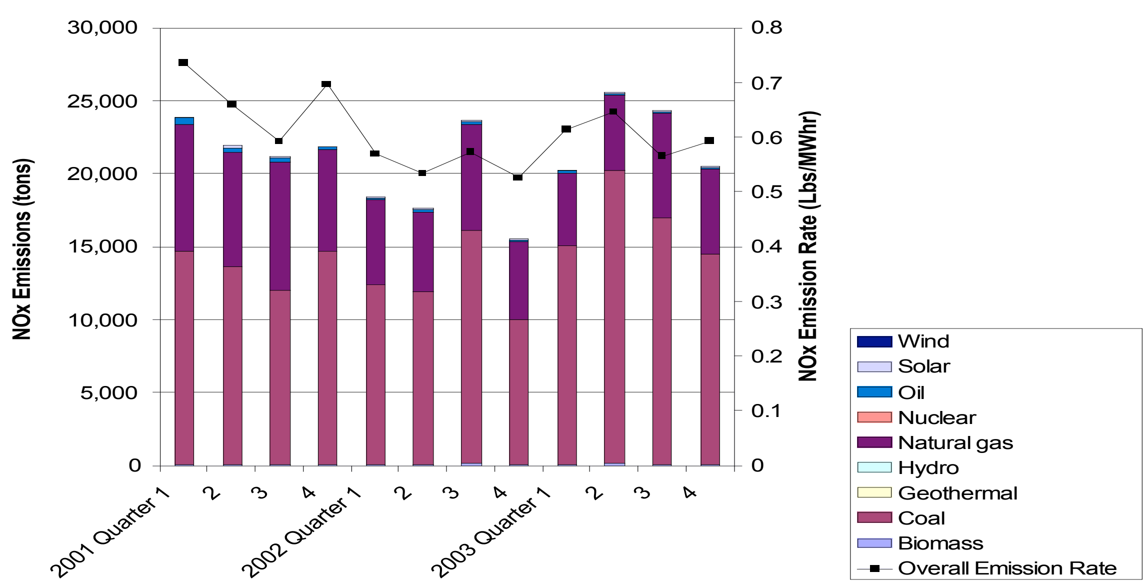

## Figure 3-4 Out-of-State Power NOx Emissions



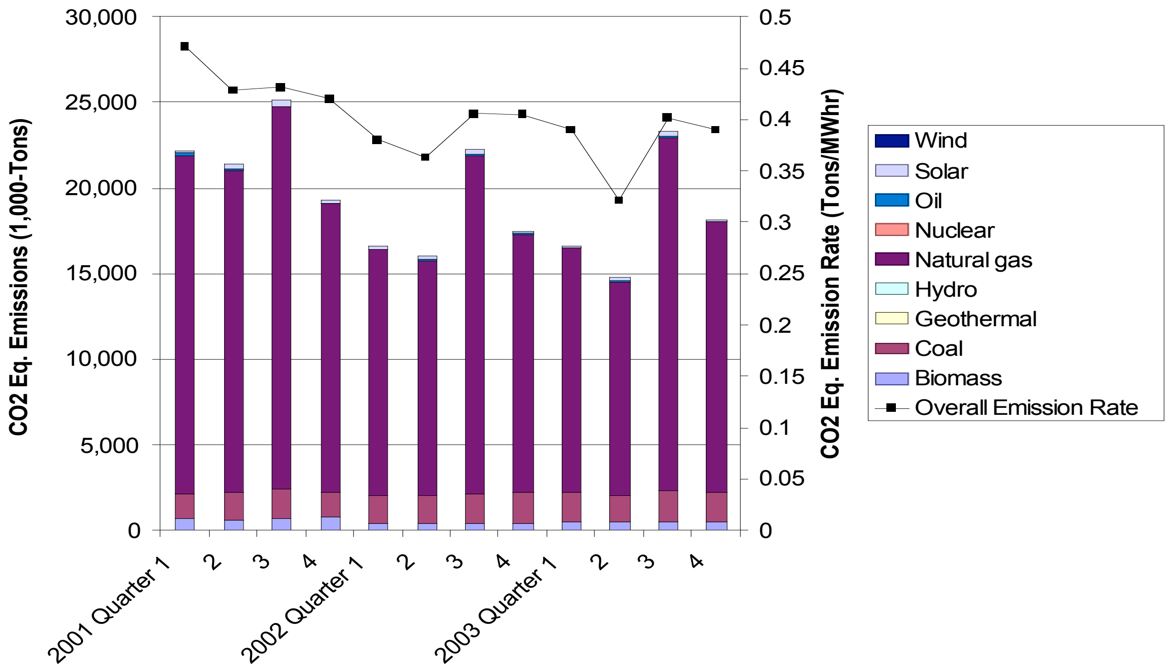
## Figure 3-5 Imported Power NOx Emissions



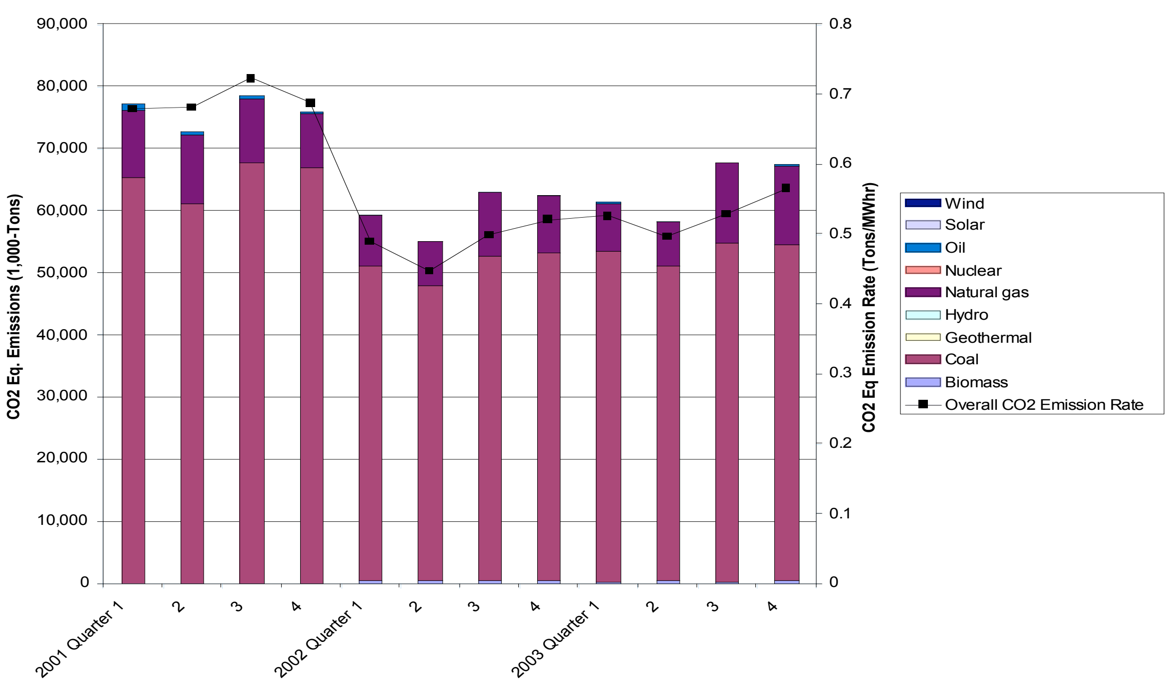

## Figure 3-6 Combined Power NOx Emissions



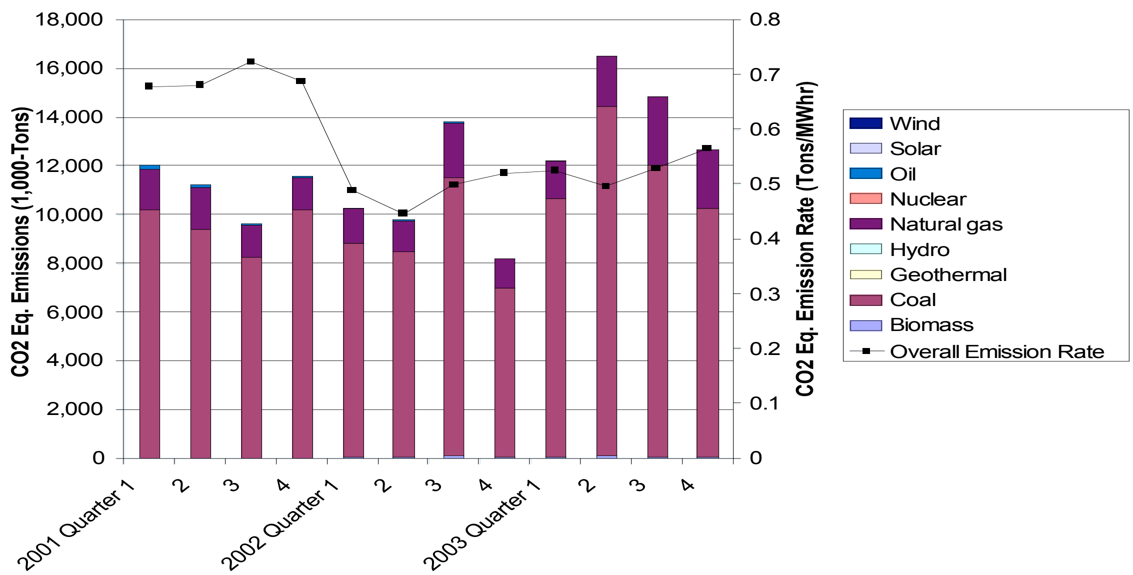
# Figure 3-7 In-State Power $CO_2$ Emissions



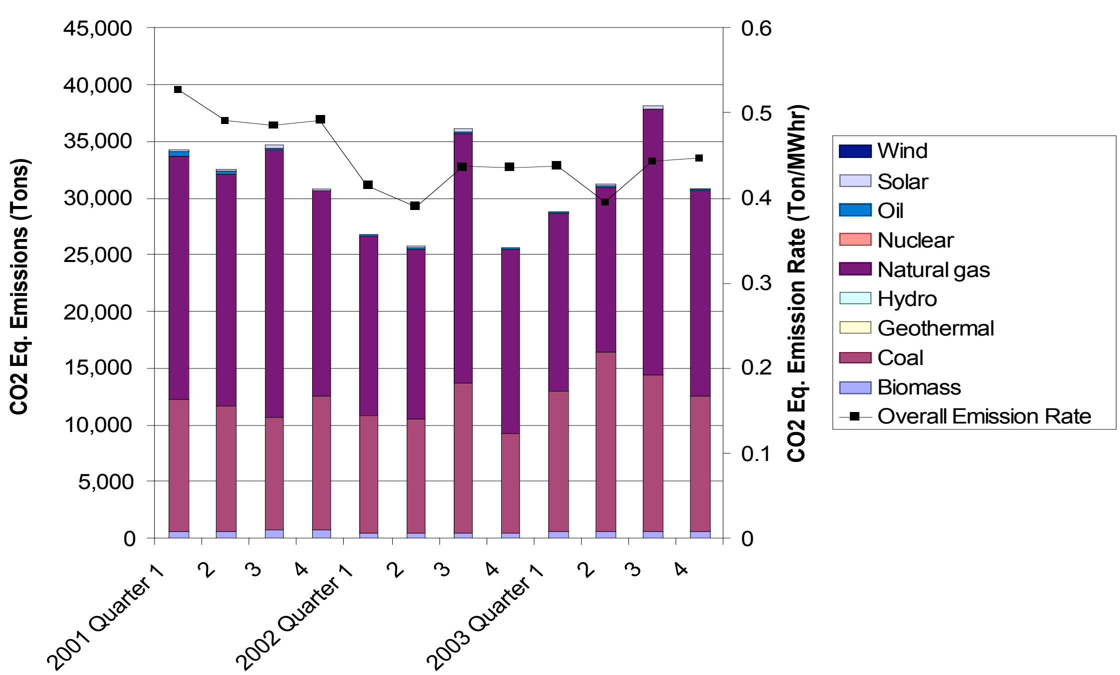

# Figure 3-8 Out-of-State Power $CO_2$ Emissions



## Figure 3-9 Imported Power $CO_2$ Emissions




## Figure 3-10 Combined Power $CO_2$ Emissions



### Air Quality Associated with Dedicated Coal Plants

The discussion above addressed imported power in general. Here, the air emissions from the six dedicated out-of-state coal-fired power plants are discussed. These power plants have generation weighted baseline emission factors (lbs/MWh) for NOx and $PM_{10}$ that are over ten times and two times the average California power generation emission factors for those pollutants, respectively. 1999 $SO_2$ emissions from these six dedicated power facilities (126,717 tons) are estimated to be just slightly less than the 1999 $SO_2$ emissions from all sources in California, almost three times greater than the 1999 $SO_2$ emissions from all stationary sources in California, and almost ninety times greater than the 1999 emissions from all California power generation sources.

The most significant air quality issue currently associated with dedicated coal-fired facilities is the visibility effect caused to surrounding Class I Areas, including the Grand Canyon National Park. For example, the Navajo and Mojave Generating Plants are major contributors to the visibility problem in the Grand Canyon, and as a result of litigation the owners of the Mojave plant agreed to add emission controls to reduce $SO_2$ emissions by 85 percent.

Estimated NOx and $CO_2$ emissions for 1996 through 2003 are provided in Figures 3-11 and 3-12. The figures indicate a general downward trend in the two pollutants, most likely due to increases in efficiency at the six coal plants.

A summary of effects, including air quality effects, for each dedicated coal plant is presented in Table 3-6.

## Table 3-6 Environmental Profiles of California Owned Coal-Based Power Plants

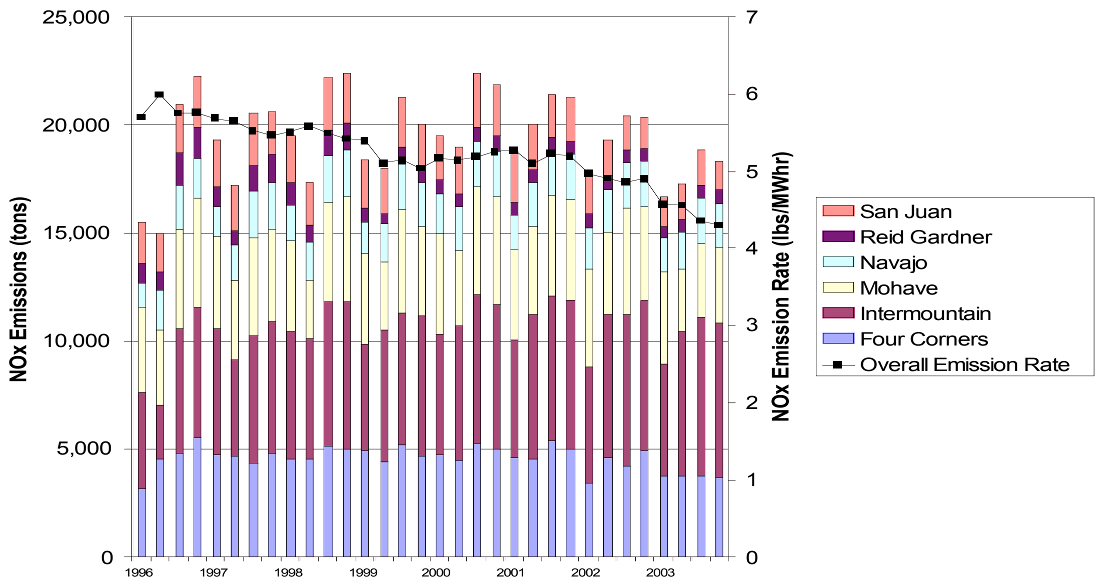
| Power Plant | Air Quality Effects | Water Resource Effects | Biological Resource Effects |
|---|---|---|---|
| | **ARIZONA** | | |
| Navajo Generating Station (2,250 MW) | • Particulate matter from $NO_x$ and $SO_2$ emissions has contributed to regional haze and reduced visibility in Grand Canyon National Park.[2]<br>• Utilizes electrostatic precipitators, 3 scrubbers, and a lined water reservoir. Attributed to being one of the cleanest coal-fired power plants in the country.[3] | • Uses approximately 28,000 acre-feet of water per year from Lake Powell. (556 gallons per MWh)<br>• Proposed additional intake system below existing intakes.<br>• Does not discharge any wastewater into the Lake Powell ("zero discharge" facility.)[1] | • Species known to occur near the power plant include the razorback sucker, bald eagle, California condor, and the peregrine falcon (listed as a Navajo Endangered Species).[1]<br>• In Coconino County, there are 21 federally listed endangered, threatened, and/or candidate species. |
| | **NEVADA** | | |

| Power Plant | Air Quality Effects | Water Resource Effects | Biological Resource Effects |
|---|---|---|---|
| Mohave Generating Station (1,580 MW) | • Particulate matter from $NO_x$ and $SO_2$ emissions has contributed to regional haze and reduced visibility in Grand Canyon National Park.[2]<br>• Plans to install $SO_2$ scrubbers, fabric filters, and low $NO_x$ burners.[6]<br>• Previously used five to ten acres for fly ash disposal, which has been reduced to one acre.[**] | • Uses approximately 20,000 acre-feet per year.[5] (656 gallons per MWh)<br>• Does not discharge any wastewater into the Colorado River ("zero discharge" facility).<br>• Uses groundwater from local wells to create coal slurry at Black Mesa coal mine, which is delivered to power plant via pipeline. | • Desert Tortoise (Federally listed as a threatened species) is located in southern Nevada.[4]<br>• Of the animal and plant species in Nevada, 25 are federally listed as endangered and 16 are federally listed as threatened. |
| Reid Gardner Generating Station (556 MW) | • Particulate matter from $NO_x$ and $SO_2$ emissions has contributed to regional haze and reduced visibility in Grand Canyon National Park.[2] | • Uses approximately 7,000 acre-feet of water per year.[5] (626 gallons per MWh)<br>• Diverts water from the Muddy River, which has been identified as one of the region's most threatened landscapes.[7] | • Desert Tortoise (Federally listed as a threatened species) is located in southern Nevada.[4]<br>• Four rare or endangered fish species (e.g., Virgin River Chub & Moapa Dace), and seven rare invertebrate species have established habitat within the Muddy River, which is used as make-up process water at power plant.[4]<br>• State & federal-listed special status species known to occur near power plant include bearpoppy, buckwheat, Mohave yucca, and cacti.[4] |
| **NEW MEXICO** | | | |
| Four Corners Power Plant (2,040 MW) | • Particulate matter from $NO_x$ and $SO_2$ emissions has contributed to regional haze and reduced visibility in Navajo National Monument.[9]<br>• Utilizes wet and dry scrubbers and fabric filters.[10] | • Uses approximately 26,000 acre-feet of water per year from Morgan Lake.[5] (591 gallons per MWh) | • Intakes water from Morgan Lake, which is an important avian migratory stop and wintering site.<br>• Of the animal and plant species in New Mexico, 41 are federally listed as threatened and/or endangered. |
| San Juan Generating Station (1,643 MW) | • Particulate matter from $NO_x$ and $SO_2$ emissions has contributed to regional haze and reduced visibility in Mesa Verde National Park.[12]<br>• Uses electrostatic precipitators and low $NO_x$ burners. | • Uses an average of 22,000 acre-feet of water per year from the Navajo Dam Reservoir and San Juan River.[11] (610 gallons per MWh)<br>• Does not discharge any wastewater ("zero discharge" facility).[11] | • Of the animal and plant species in New Mexico, 41 are federally listed as threatened and/or endangered. |
| **UTAH** | | | |
| Intermountain Power Plant (1,640 MW) | • Particulate matter from $NO_x$ and $SO_2$ emissions may threaten visibility in Zion, Bryce Canyon, Capitol Reef, Canyonlands, Great Basin, and Arches National Parks.<br>• Uses fabric filters and limestone scrubbers. | • Uses approximately 21,000 acre-feet of water per year.[5] (531 gallons per MWh)<br>• Intakes water from the DMAD Reservoir in the Sevier River Basin. | • Of the animal and plant species in Utah, 43 are federally listed as threatened and/or endangered. |

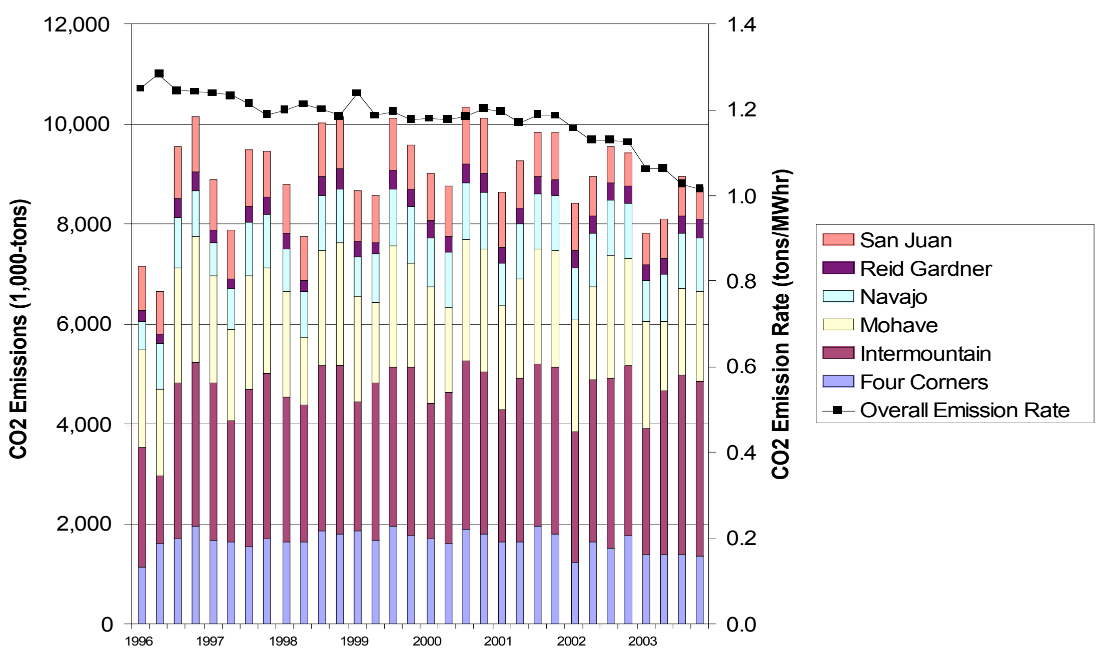
| Power Plant | Air Quality Effects | Water Resource Effects | Biological Resource Effects |
| --- | --- | --- | --- |

[1] Environmental Assessment for the Navajo Generating Station Water Intake Project, March 2005.
[2] http://www.cleartheair.org/haze/sources.vtml
[3] http://www.srpnet.com/about/stations/navajo.aspx
[4] http://www.nevadapower.com/comenv/env/biological/
[5] http://www.cfcae.org/Conventional_Generation/Water._Use.htm (estimate assumes 12.5 acre-feet of water per MW of the operating capability)
[6] http://www.sce.com/PowerandEnvironment/BetteringEnergyEfficiencyPowerSources/Coal
[7] Nature Conservancy's Mojave Desert Ecoregional Assessment
[8] http://nm.audubon.org/iba/ibawriteups/morgan.html
[9] http://www.nps.gov/nava/adhi/adhi8b.htm
[10] http://www.srpnet.com/about/stations/fourcorners.aspx
[11] http://www.pnm.com/systems/sj.htm and http://www.pnm.com/environment/sj_water.htm
[12] http://www.grandcanyontrust.org/programs/air/san-juan.php
** Nevada Department of Conservation and Natural Resources: Nevada Environmental Commission, Hearing Archive, December 11, 1995.
[13.] (Source: National Park Service, May 26, 2005, Great Basin National Park Air Quality Page, http://www.great.basin.national-park.com/air.htm.)

## Figure 3-11 Dedicated Coal Power NOx Emissions




## Figure 3-12 Dedicated Coal Power $CO_2$ Emissions



## Contamination Issues Regarding Mercury and Lead Deposition

Coal combustion results in emission of over 65 different compounds, including organic emissions and trace metals such as mercury and lead. The level of emissions depends on a variety of factors, including the composition of the fuel, the type and size of the boiler, firing conditions, load, type of control technologies, and the level of equipment maintenance.

Coal-fired power plants have relatively high emissions of mercury and lead. However, mercury and lead emissions from coal-fired power plants are not a major component of total mercury and lead emissions from the western states. The majority of mercury emissions come from gold mines and the majority of lead emissions come from metal refining operations.

Mercury pollution is of particular public concern due to its health effects, especially on children and infants. Mercury exposure at high levels can harm the brain, heart, kidneys, lungs, and immune system of people of all ages. Additionally, high levels of methylmercury in the bloodstream of unborn babies and young children may harm the developing nervous system.[37] Although concentrations in air are usually low, once mercury enters soils or waters through air deposition, it can bioaccumulate in fish and animal tissue, resulting in concentrations that can be thousands or millions of times greater than the concentrations found in soil and water. Microorganisms may convert inorganic mercury to methylmercury, which can work its way up the food chain to enter the systems of larger fish, and eventually be consumed by humans.[36] People who frequently consume large amounts of fish are more highly exposed.

Coal-burning power plants are the largest human-caused source of mercury emissions to the air in the U.S., accounting for about 40 percent of the 112 tons of domestic mercury emissions in 1999. The western states' 1999 mercury emissions, including California, are estimated by U. S. EPA to be approximately 26 percent of the domestic total, or 29.4 tons;[38] however the vast majority of these emissions are from sources other than coal-fired power plants, with perhaps as much as 6 tons, or approximately 20 percent, coming from coal-fired power plants.

Mercury emissions from power plants are due to the trace amounts of mercury in the coals (including lignite) that are combusted. Mercury is a volatile metal, so it vaporizes during the combustion process and is emitted in the exhaust gases. The amount of mercury available for release is variable, depending on the factors mentioned above. Nationwide, approximately 75 tons of mercury are contained in coal delivered to power plants each year. As an ancillary benefit of existing air pollution controls on coal burning power plants such as fabric filters for particulate matter, $SO_2$ scrubbers and selective catalytic reduction (SCR) to control NOx emissions, about 25 tons of this mercury is captured, leaving about 50 tons to be actually emitted into the air.

Mercury emissions can be controlled either pre- or post-combustion. Coal cleaning is a technology that can reduce the amount of mercury in the coal prior to its combustion. Post-combustion controls include fiber filters, flue gas desulfurization, and activated

carbon injection coupled with fabric filters. The effectiveness of emission controls is dependent on the combustion technology and the specific type of coal being fired.
In December 2000, U.S. EPA found that it was "appropriate and necessary" to regulate coal- and oil-fired electric utilities under section 112 of the Clean Air Act. This finding, known as the Utility Air Toxics Determination, triggered a requirement for U.S. EPA to propose regulations to control air toxics emissions, including mercury, from these facilities by December 15, 2003.

On March 15, 2005, the U.S. EPA issued the Clean Air Mercury Rule to reduce mercury emissions from coal-fired power plants. The Clean Air Mercury Rule establishes standards of performance limiting mercury emissions from new and existing utilities and creates a market-based cap-and-trade program. In the first phase, nationwide mercury emissions will be capped at 38 tons by 2010 by taking advantage of “co-benefit” reductions realized by sulfur dioxide ($SO_2$) and nitrogen oxide (NOx) air pollution control technologies. In 2018, the second phase sets a cap of 15 tons, a reduction of 33 tons or nearly 70 percent from the current emissions level of about 48 tons. The U.S. EPA assigned each state and two Indian tribes a mercury emissions “budget” based on hypothetical allocations calculated for each generating unit under the future 38 and 15 tons per year caps (See Table 3-7).

For the western U.S., the cap for 2010 through 2018 would allow total mercury emissions to increase slightly from 2000 levels, although totals for individual states could either increase or decrease. Thus, there may be no overall reductions until 2018, when the 15-ton emission cap takes effect. The Clean Air Mercury Rule will be proportionately more effective in reducing mercury emissions in other areas of the U.S., where power generation is a larger contributor to total mercury emissions than it is within the western states as a whole.

On March 29, 2005, the U.S. EPA determined that no public health hazards from coal combustion are reasonably anticipated to occur from any of the approximately 65 compounds emitted when federal air pollution control requirements are taken into account.[10] That determination was based, in part, on reductions in mercury emissions that are expected to occur following implementation of the recently-issued federal Clean Air Mercury Rule. Consequently, mercury emissions will not need to be controlled at each facility through the application of maximum-achievable control technology.

## Table 3-7 State and Tribal Mercury Emissions Budgets for 2010 and 2018 (pounds)

| State | 2010-2017 | 2018 and thereafter |
|---|---|---|
| **Arizona** | 908 | 358 |
| **California** | 82 | 32 |
| **Navajo Nation**[1] | 1202 | 474 |
| **New Mexico** | 598 | 236 |
| **Nevada** | 570 | 224 |
| **Utah** | 1012 | 400 |
| **Ute Indian Tribe**[2] | 120 | 48 |
| **Total** | 4492 | 1772 |

[1] Navajo (AZ) + 4 Corners (NM) plants included in Navajo nation

[2] Bonanza (UT) plant included in Ute tribe

On January 26, 2004, the U.S. EPA's Children's Health Protection Advisory Committee submitted comments on the then-proposed mercury rule. They stated that it did not go as far as was feasible to reduce mercury emissions from power plants, and thus would not sufficiently protect the nation's children.[11] The Advisory Committee expressed a number of additional concerns:

- The unique vulnerabilities of children, infants, and women of child-bearing age were not adequately considered in the development of the U.S. EPA's proposed rules.
- Mercury should be a regulatory target in its own right, rather than regulated indirectly through side benefits obtained from regulating sulfur dioxide and nitrogen oxide.
- A cap and trade program may not address existing hot spots and may create new local hot spots for mercury, disproportionately impacting local communities.
- The U.S. EPA needs to go beyond the minimum required by statute to protect children from mercury exposure.
- EPA should establish a rule that results in the maximum emissions reductions feasible; the best available technology for mercury should be utilized in order to reach the greatest maximum benefit for children's health.

Energy Commission staff view the comments of the U.S. EPA's Children's Health Protection Advisory Committee as valuable and agree in principle with them. We believe that the U.S. EPA should strive to ensure that the mercury rule does not result in any localized hot spots and provides adequate protection for children, infants, and women of child-bearing age.

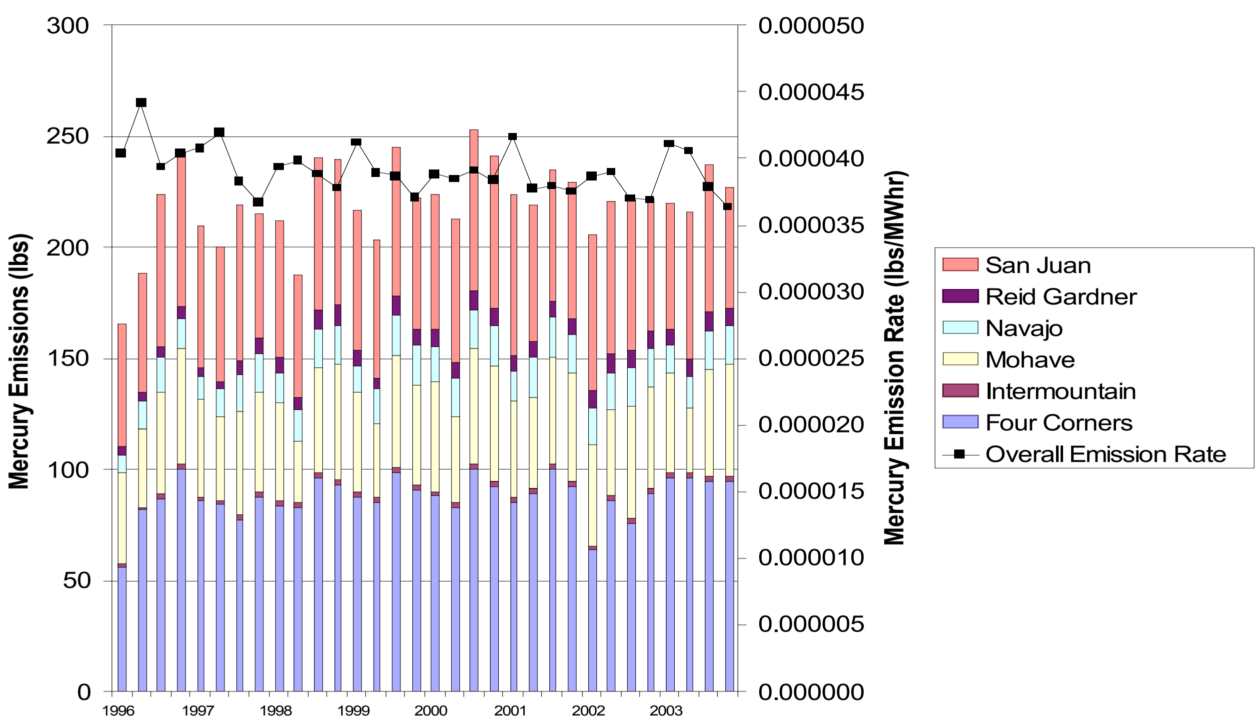
Table 3-8 presents mercury emissions for the year 2000 for coal-fired generation owned wholly or in part by California entities. Emissions for the year 2000 are similar for those in 1997 and 1998, with no clear trend among the different units. Figure 3-13 shows mercury emissions for coal plants owned wholly or in part by California entities.

## Table 3-8 Mercury Emissions from Coal Generating Plants with CA Ownership (Year 2000 Emissions in Pounds)

| Power Plant | % CA Ownership | Plant Capacity - MW | Plant Mercury Emissions |
|---|---|---|---|
| **Navajo** | 21.21 | 2409 | 321.36 |
| **Four Corners** | 34.61 | 2270 | 1041.88 |
| **San Juan** | 24.19 | 1779 | 1108.63 |
| **Reid Gardner** | 29.91 | 612 | 106.74 |
| **Mohave** | 66.00 | 1636 | 249.67 |
| **IPP** | 100.00 | 1640 | 9.4 |

source: U.S. EPA eGRID data

## Figure 3-13 Dedicated Coal Power Mercury Emissions

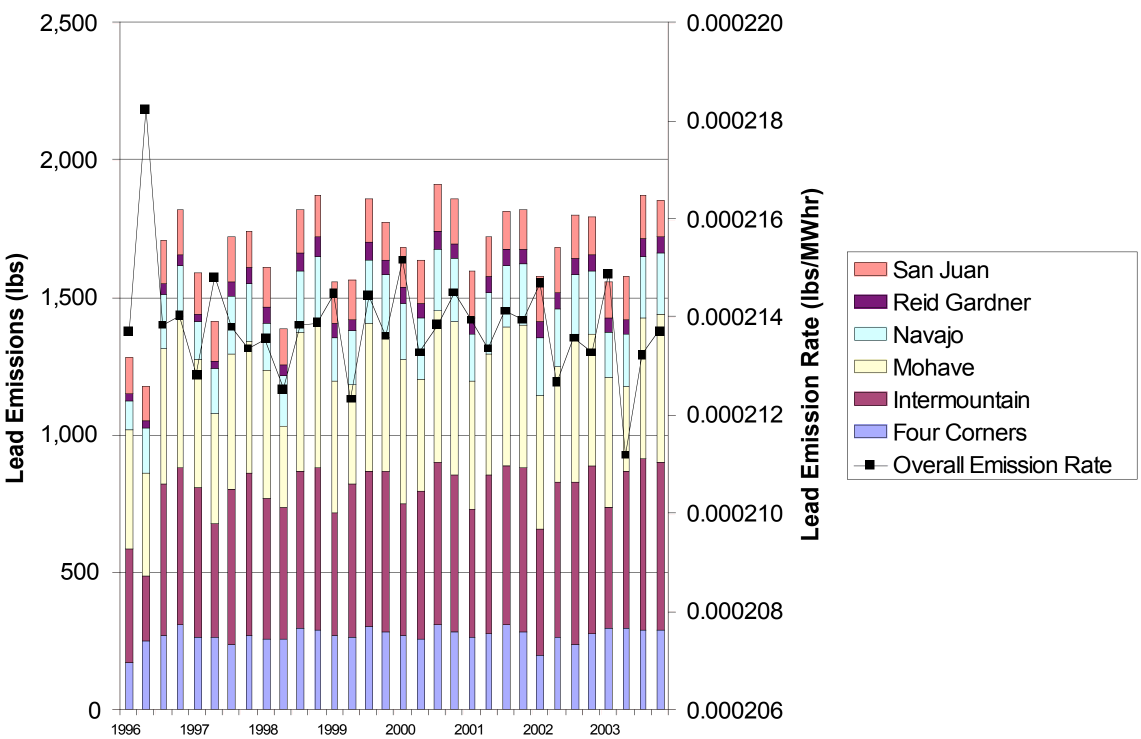



An alternative technology to conventional pulverized coal combustion includes Integrated Coal Gasification Combined Cycle. This type of facility converts coal into gas that is combusted in a combined-cycle unit. Gasification removes impurities from the coal gas before it is combusted, resulting in lower emissions of sulfur dioxide, particulates and mercury when compared with conventional combustion. Sulfur in the coal emerges as hydrogen sulfide and can be captured and used in the chemical industry. In some methods, the sulfur can be extracted in a form that can be sold commercially. Likewise, nitrogen typically exits as ammonia and can be scrubbed from the coal gas by processes that produce fertilizers or other ammonia-based chemicals.

Air emissions from such a facility may be comparable to natural gas-fired combined-cycle units. Integrated Gasification Combined Cycle technology also results in improved efficiency compared with conventional pulverized coal.

**Lead** emissions from coal-fired power plants, like mercury, are due to trace amounts of lead in the coals that are combusted. The amount of lead available for release is variable and dependent upon coal composition and the particulate and other controls used at each plant. Coal-fired power plants are the second largest source of anthropogenic lead emissions.[36] In addition to impacting human health, elevated levels of lead in the water system can impair the reproductive systems of some aquatic species and cause blood and neurological changes in fish.[37] Figure 3-14 shows lead emissions for coal plants owned wholly or in part by California entities.

**Figure 3-14 Dedicated Coal Power Lead Emissions**




## *Water Effects and Key Issues*

Existing power plants, with limited exceptions, use water for cooling. Wet cooling systems can be designed as either once-through or closed-loop systems. In once-through cooling systems, water is withdrawn from a source, pumped through a heat exchanger, and discharged at a higher temperature, usually to the same body of water from which it was withdrawn. In closed-loop cooling systems, water is withdrawn from a source, circulated through heat exchangers, cooled, and recycled. Subsequent water withdrawals for a closed-loop system are used to replace water lost to evaporation, blowdown, drift, and leakage.

The dedicated coal-fired plants identified on Table 3-2 use wet cooling towers. They use approximately 530 to 656 gallons of water for every MWh generated (see Table 3-6 and Attachment B). Wet cooling is the primary water consumer for these six plants. Other boiler-type power plants, regardless of the type of fuel used, use similar quantities of water per MWh of generation if they use closed-loop wet cooling. In comparison, a combined-cycle gas turbine power plant (7F or 7H frame turbine) uses anywhere from 215 to 240 gallons of water for every MWh generated, approximately 40 percent of the water used in a traditional coal-fired plant when both use wet cooling towers. Simple cycle gas turbine power plant water consumption is fewer than 100 gallons per MWh generated.

Water consumption for use in coal power plants can worsen existing water shortages in areas suffering from drought. The severity of the drought in the Southwest has been documented in a study by the Hewlett Foundation. The report considered the states of Arizona, Colorado, Idaho, Montana, Nevada, New Mexico, Utah, and Wyoming: six of the ten states considered in this report. The study identified coal-fired plants as one of the biggest water consumers among all fuel types in electricity generation. With the demand to build additional energy facilities in response to the energy shortage of 2000/2001 and the fact that coal-fired plants are a dominant source of electrical power in the Southwest, the stress on water resources is expected to worsen.[38] The impact of the drought has already had an effect on existing and proposed facilities. For example, the Navajo Generating Station is currently undergoing environmental review for a new water intake. A new intake is needed to ensure further availability of cooling water for this plant because the surface water elevation in Lake Powell has dropped significantly due to the five-year drought in the Southwest.[39]

Additional pollutants (i.e., arsenic, lead) may be leached into nearby bodies of water from the coal waste by-products that are stored outside the plant and exposed to rain-water.[40] A discussion of the specific effects to water attributable to each power plant is listed in Table 3-5.

As with all conventional power plants, coal-based power facilities are regulated through issuance of a NPDES permit which specifies the types, quality and amounts of water releases that may occur at each facility. The coal industry has developed technologies to reduce the amount of wastewater discharge from coal-based power plants. Many coal power plants are zero discharge facilities which use evaporation equipment (e.g., evaporation ponds, vapor compression evaporators) to treat and remove cooling water. In addition, wastewater discharge can be directed through a floating weir in order to optimize evaporative cooling to the atmosphere before discharging it into nearby lakes and rivers.

The Mohave Generating Station is the only existing plant that receives its coal through a pipeline, which connects the power plant to the Black Mesa Mine in Arizona, approximately 275 miles away. At the mine, sub-bituminous coal is crushed, sized, and mixed with water to form a 50:50 slurry that is pumped to the power plant. The source of water for the slurry is groundwater from the confined parts of the N aquifer, which is situated beneath Black Mesa on lands belonging to the Navajo Nation and the Hopi Tribe.[41] The N aquifer also serves municipal water needs for the 5,400 square-mile Black Mesa area.[42] The Black Mesa Mine pumps approximately 4,400 acre-feet of water per year for the coal slurry.[43]

Until 1963, the Consolidated Coal Company in Ohio had operated a 108-mile slurry pipeline that was eventually closed in favor of rail transport.[44] Due to the large amounts of water needed for a slurry operation, the U.S. Office of Technology Assessment recommended in the late 1970s that slurry pipelines be used only in areas with abundant water resources.[44]

Previous coal leases with the Navajo and Hopi have allowed the operators of the Black Mesa Mine (i.e., Peabody Western Coal Company) to mine the coal and extract the groundwater on tribal lands. However, current litigation over past royalty payments for the coal may affect Mohave's future coal supply. Other possible water sources for the slurry pipeline would be the Colorado River, which would require the construction of a water pipeline from the river to the coal mine.[45] As there is no rail line in the vicinity of the Mohave Generating Station, coal could not be currently transported by railroad.

Upon reaching the generating station, the slurry must be dewatered through the use of one of 40 centrifuges, and the finely-ground coal must be separated through the use of clarifiers (i.e., clariflocculators). After an additional heat-applied drying process, the coal is burned and the reclaimed water is used in the cooling system.[46] In addition, the generating station must also use water from the Colorado River for its cooling operations. The Southern Nevada Water Authority has agreed to provide the Mohave plant with 16,000 acre-feet per year from the Colorado River through July 2026.[47]

Effects resulting from the slurry pipeline include twelve pipeline failures between 1994 and 1999, eight of which resulted in discharges of coal or coal slurry into local washes. The most recent pipeline discharge occurred on March 24, 2003. Water pollution has also been created from the maintenance operations that use fresh water to wash the slurry residues from the pipeline walls.

Cooling water that is used at the Mohave plant is disposed of in lined wastewater evaporation ponds. Other forms of coal wastewater are also disposed of in storage ponds at the plant facility. As a zero discharge facility, the Mohave Generating Station cannot discharge any wastewater or cooling water into groundwater or surface waters. However, due to pre-regulation leakage at the site, the water below the power plant has already been impacted and an extensive groundwater remediation program has been conducted.[48]

## *Biological Effects and Key Issues*

Table III-6 presents some information on the biological resources located near or potentially near dedicated coal facilities. All of the dedicated coal facilities are located in the Southwest Region. Each of the states with dedicated coal facilities has significant biological resources that could be impacted by plant operations. Effects on biological resources may include destruction or impairment of habitat from water intake structures or from the siting of power plant facilities and infrastructure. The greatest impact from coal generation is often considered to be its production of SOx emissions, which combine with oxygen to form $SO_2$. As $SO_2$ precipitates out of the atmosphere, it can adversely impact wildlife and forests over time, a condition that is called acid rain. However, $CO_2$ emissions from coal-based power plants may also negatively impact biological resources. See further discussion of biological effects for natural gas plants.

### *Coal Mining, Processing, and Shipping*

Due to the 1990 Clean Air Act Amendments, the coal used by the electricity industry has shifted from the high sulfur Northern Appalachian and Illinois Basin regions to the lower sulfur regions of the Powder River Basin and the Rockies. The Powder River Basin of Wyoming is the leading source of low-sulfur coal in the U.S., accounting for approximately 32 percent of coal supplies nationwide. Coal from the Rockies (primarily Colorado and Utah) is similar in sulfur content to Wyoming coal, but has a substantially higher range of heating values. The Rockies region accounts for approximately four percent of coal supplies nationwide. Over 85 percent of the coal distributed from the Power River Basin region is transported by rail.[49]

The dedicated coal plants receive their coal supplies from coal mines in the Powder River Basin and the Rockies, as follows:

- Nevada coal-based power plants (Mohave and Reid Gardner) receive approximately 64 percent of their coal from the Black Mesa coal field in northeastern Arizona, while approximately 32 percent is shipped from Utah and four percent is mined in Wyoming and Colorado.[49] Shipment generally occurs via railroad; however, the Mohave power plant receives 100 percent of its coal from the Black Mesa coal field via a coal slurry pipeline. The Black Mesa Pipeline delivers approximately five million tons of coal per year to the Mohave plant.
- The Navajo power plant in Arizona receives coal via railroad from the Kayenta Mine, which is located in the state.[50]
- In New Mexico, the Four Corners Power Plant receives its coal from the Navajo mine via railroad, and the San Juan Generating Station receives its coal from the San Juan mine via truck, both of which are located in the San Juan Basin in the northwestern part of the state.
- The Intermountain Power Plant receives much of its coal from Utah mines (i.e., West Ridge Mine, located in the Book Cliffs region in central Utah) via truck; it has also negotiated coal purchase contracts from mines in Colorado.

Mining operations may generate both large amounts of saline water and contaminated water from coal cleaning operations. To reduce effects from the discharge of saline wastewater into nearby lakes and rivers, discharges are limited to periods of high water flow when dilution would mitigate potential effects. However, discharged water may also be contaminated from mining operations. Similar to power plants, coal mining is subject to the emissions release and water use requirements of a number of permits, such as a NPDES permit, industrial discharge permit, water appropriation and use permit, and erosion/sediment control approval permit.

In addition, coal mining requires large amounts of land, especially in the case of surface mining. Approximately 1,680 acres of land in the U.S. are currently being disturbed by coal mines that supply electric power plants.[51] In order to mitigate effects and restore mined areas, mining companies must specify reclamation plans for post-mine land use (i.e., revegetation, future agricultural, commercial, recreational uses); however, mining companies may not necessarily be required to restore mined areas to their previous habitat.

The waste generated by the coal-power industry in the U.S. is equivalent to approximately 100 million tons of coal combustion products (i.e., fly ash, sludge from scrubbers, boiler ash, and boiler slag).[52] While some of this waste is recycled in commercially beneficial uses (i.e., Portland cement replacement), more than 70 million tons of byproducts a year are disposed of in impoundments and landfills.[52] In order to reduce the amount of discarded coal byproducts, and the associated contamination from storage and disposal, the Department of Energy is researching applications of these byproducts for other uses, such as enhancing depleted soils in certain agricultural applications and immobilizing hazardous wastes for safer disposal.

Biological resource effects are also attributed to coal processing and transportation. Two types of mining processes may be used to extract coal. Surface mining is used to access coal seams that are typically within 200 feet of the surface, and requires heavy equipment (e.g., draglines, power shovels, bulldozers, front-end loaders) to remove the soil and rock that cover the coal. Underground mining is used to access coal seams that are several hundred feet below the surface, creating a vertical shaft to access the coal. Due to the expense associated with underground mining, approximately 63 percent of all produced U.S. coal is accessed through surface mining.[53]

Before transport, coal is cleaned and prepared at the mining site through a process that removes dirt, rock, ash, sulfur, and other impurities. Nearly 62 percent of all coal shipments are transported via railroad, while 25 percent are transported by barge and truck.[49] Emissions from railroad locomotives and coal dust have also contributed to air quality effects.

## Hydropower

### *Overview of Hydropower Resources*

Western North America, including the western U.S., Canada (British Columbia), and Mexico (Northern Baja California), has an existing 53,200 MW of hydropower energy capacity. Hydropower is important to the discussion of out-of-state power because California receives over 7,000 MW of power per year from hydroelectric power, depending upon drought, high rainfall years, and market conditions.[54]

#### Northwest Region

Washington has the greatest hydropower generating capacity in the West, with 312 hydroelectric power plants with an installed capacity of approximately 20,693 MW. Canada (British Columbia) has the second-largest hydroelectric generation capacity in the West, followed by Oregon. Table 3-9 below presents the total hydroelectric capacity per state and province in the Northwest Region.

**Southwest Region**

In the Southwest Region, the total hydroelectric capacity is approximately 5,567 MW. Arizona has the greatest installed hydroelectric capacity with a total of 45 hydroelectric power plants. Table 3-10 provides a summary of the hydropower generation profile for the Southwest Region.

**Table 3-9 Total Hydroelectric Installed Capacity by State and Province in Northwestern Region**

| State | Installed Capacity (MW) | Number of Power Plants |
|---|---|---|
| Idaho | 2,472 | 228 |
| Montana | 2,440 | 99 |
| Oregon | 8,201 | 208 |
| Washington | 20,693 | 312 |
| Wyoming | 297 | 36 |
| British Columbia | 13,533 | 133 |
| **TOTAL** | **47,636** | **1,016** |

Source: National Renewable Energy Laboratory. Data for 2002; Statistics Canada. Data from 2003.

**Table 3-10 Total Hydroelectric Installed Capacity by State and Province in Southwestern Region**

| State | Installed Capacity (MW) | Number of Power Plants |
|---|---|---|
| Arizona | 2,992 | 45 |
| Colorado | 1,164 | 83 |
| Nevada | 1,045 | 19 |
| New Mexico | 79 | 8 |
| Utah | 284 | 97 |
| Mexico | -- | 133 |
| **TOTAL** | **5,567** | **385** |

Source: National Renewable Energy Laboratory, Data through 2002. U.S. Department of Energy.

Well-known examples of hydroelectric facilities in Arizona include Hoover Dam (on the border with Nevada) and Glen Canyon Dam (near the border with Utah). Together these dams can generate over 3,000 MW of electric power. The reservoirs that each dam creates (Lake Mead and Lake Powell) are heavily used for recreation. Other hydroelectric dams include those on the Salt River and the Colorado River below Hoover Dam. Several sites have been suggested over the years for additional large projects. These were rejected because they would infringe on scenic areas, such as the Grand Canyon.

According to the 2003 EPR, new hydropower development opportunities that could influence California's electricity imports are located in Oregon, Arizona, and Nevada. The opportunities in Oregon are estimated at 19,000 MW of new hydropower capacity. In Arizona, they are estimated at approximately 5,000 MW and in Nevada at 2,000 MW.[55]

## *Air Effects and Key Issues*

Hydroelectric power production does not cause significant air emissions. A very small amount of $PM_{10}$ emissions would occur via droplet drift at facilities that open overflow spillways during periods of high water or as necessary for maintaining regulated downstream flows.

A minor amount of criteria pollutant emissions could result from miscellaneous activities required to maintain the hydroelectric facilities. Historically, hydroelectric facilities, more than other power technologies, have allowed for an increase in secondary emission sources such as recreational boating, commercial shipping (such as barge transportation), and secondary industrial and commercial development that is reliant on the cheap power (such as aluminum refining) or water resources (such as agriculture).

### *Water Effects and Key Issues*

Hydroelectric power plants, by their nature, require large volumes of freshwater for electricity generation. Although the generation process consumes little to no water, some water evaporates from the reservoirs and from pumped-storage operations.[56]

Dams associated with large-scale hydropower generation (i.e., greater than 30 MW) affect the flow of rivers and alter riparian ecosystems. While wide variations occur from facility to facility and regionally, the environmental effects of dams generally fit within two categories: those due to the existence of the dam and reservoir, and those due to the pattern of dam operation.[57] Table 3-11 provides a summary of the primary water-related effects associated with dam placement and operation.

Examples of mitigation features that have been applied to reduce some water-related effects include:

- Implement sediment dredging to decrease sediment from behind the dam, thus decreasing turbidity.
- Implement flushing and piping techniques to move non-contaminated sediment downstream.
- Implement aeration techniques to oxygenate water to increase dissolved oxygen levels in surface water.
- Release greater amounts of flow downstream to reduce downstream water temperatures.

**Table 3-11 Primary Water-Related Effects of Dam Placement and Operation**

| **Dam/Reservoir Placement** |
| --- |
| ▪ Imposition of a reservoir in place of a river valley (loss of habitat, community, agriculture)<br>▪ Changes in downstream morphology of riverbed, delta, coastline due to altered sediment load (increased erosion)<br>▪ Changes in downstream water quality:<br>- Modified water temperatures<br>- Modified nutrient loading<br>- Changes in turbidity<br>- Increased dissolved gases<br>- Increased concentration of heavy metals and minerals<br>▪ Changes in upstream water quality:<br>- Algae blooms |

| |
|---|
| - Increasing mercury levels due to accumulating and decaying vegetation in reservoirs<br>- Bacterial growth/blooms<br>- Increasing heavy metal and mineral concentrations<br>▪ Reductions in biodiversity due to blocking of movement of organisms (e.g. salmon) and because of above changes |
| **Dam Operations** |
| ▪ Changes in downstream hydrology:<br>- Changes in total flows<br>- Changes in seasonal flows (e.g. Spring flood becomes Winter flood)<br>- Short-term fluctuations in flows (sometimes hourly)<br>- Change in extreme high and low flows<br>▪ Changes in downstream morphology caused by altered flow pattern<br>▪ Changes in downstream water quality (see above) caused by altered flow pattern<br>▪ Reductions in riverine/riparian/floodplain habitat diversity, especially because of elimination of floods |

Source: International Development Studies Network, Dams in Development: Perspectives - Environmental, Social and Economic Effects of Dams - Environmental Effects. http://www.idsnet.org/Resources/Dams/Development/DinD.html?IDSNet+Icon.x=36&IDSNet+Icon.y=7

In addition to the direct effects of dam placement and operations, regional climatic variables (e.g. seasonal precipitation patterns and temperatures), population growth, cycles of drought, overall water availability and demand, and peak demands in energy need collectively affect how dams are operated and thus their direct and indirect water-related effects. For example, in the Southwest peak energy demand in the summer is generally 50 percent higher than in winter, while in the Pacific Northwest, peak energy demand in the winter is about 20 percent higher than it is in summer.[58] The operation (dam water outflow) of hydroelectric facilities is calibrated to meet these demands, which can impose artificial stream flow regimes downstream of dams, such as unusually high summer flows in streams/rivers that typically have little or no flow in the summer or no or minimal winter flows in streams/rivers that typically have high flows. [58 59]

In both the Southwest and Northwest, hydroelectric dam operations have created direct and indirect effects related to water. For example, in the Southwest, effects due to operation of the Upper and Lower Colorado River dams (such as the Blue Mesa, Crystal, Morrow Point, Flaming Gorge, Navajo, Glen Canyon, Hoover, and Parker Dams) have triggered the establishment of, among other things, the Colorado River Basin Salinity Control Forum, Lake Mead Water Quality Forum, San Juan River Basin Recovery Implementation Program, Lower Colorado River Multi-Species Conservation Program, and Glen Canyon Dam Adaptive Management Program to address water quality and use and their associated effects on habitat and threatened and endangered species.[59 60 61]

In the Northwest, both regulatory agencies and the public are becoming increasingly concerned with water flow and quality effects of hydroelectric dams on salmon and trout (addressed below). An example of water-related concerns in the Northwest is the FERC's current relicensing of the Klamath River Hydroelectric Project. During the relicensing process, the public has raised the following concerns with current operations of the facility: water effects regarding high nutrient levels, temperature increases and decreases, algae blooms, high nitrogen, ammonia and pH levels, depressed dissolved oxygen levels, and fish kills.[62]

## *Biological Effects and Key Issues*

The construction and operation of hydroelectric dams directly affects aquatic biological resources. Dams obstruct river flows, alter nutrient cycles, block fish migration, result in fish injury and death due to turbine operations, cause supersaturation, and disrupt temperature regimes and dissolved oxygen levels favorable to aquatic life. Prime habitat is also commonly lost, and exotic fish species are often introduced.[63] In addition to the direct effects of dams on various aquatic species, the loss and/or reduction of fish species and habitat affects the economic viability of commercial fishermen and fisheries, compromises Native American Tribal fishing rights, and diminishes recreational fishing opportunities.[63]

A key concern in the Northwest is the diminishing population of anadromous (seagoing) fish, such as chinook, sockeye and coho salmon and steelhead. As these anadromous fish populations have declined, their situation as either threatened or endangered under the Federal Endangered Species Act (FESA) has become more precarious. Table 3-12 provides a list of all fish species (anadromous and non-anadromous) that are designated as threatened or endangered under the FESA in the Northwest Region (see Attachment D).

Within British Columbia, protected fish species include the Dace (*Rhinichythys sp.*), Stickleback (*Gasterosteus sp.*), Sturgeon (*Acipenser transmontanus*), and Sucker (*Catostomus sp*). [64]

Existing and new development, including the licensing and relicensing of hydroelectric power plants, must mitigate potential effects to these threatened and endangered species to ensure compliance with the FESA. Mitigation measures for dam operations to minimize effects on fish species, particularly anadromous fish species, include transporting them in trucks and barges to get them past dams, constructing dam bypass systems (ladders, side channels and slides), supporting hatcheries for river stocking, seasonal dam water flow (release) modifications to support fish species and migration, and installing turbine and intake screens and spillway flippers.[65] [66] [67]

## Table 3-12 Threatened and Endangered Fish Species of the Northwest Region of the U.S.

| Species | Scientific Name | Status* | Idaho | Montana | Oregon | Washin g-ton | Wyoming |
|---|---|---|---|---|---|---|---|
| Chub, Borax Lake | *Gila boraxobius* | E | | | X | | |
| Chub, Hutton tui (Hutton) | *Gila bicolor ssp.* | T | | | X | | |
| Chub, Oregon | *Oregonichthys crameri* | E | | | X | | |
| Dace, Foskett speckled | *Rhinichthys osculus ssp.* | T | | | X | | |
| Dace, Kendall Warm Springs | *Rhinichthys osculus thermalis* | E | | | | | X |
| Pikeminnow | *Ptychocheilus lucius* | E | | | | | X |
| Salmon, chinook | *(Oncorhynchus (=Salmo) tshawytscha* | T | X | | X | X | |
| Salmon, chum | *Oncorhynchus (=Salmo) keta* | T | | | X | X | |
| Salmon, coho | *Oncorhynchus (=Salmo) kisutch* | T | | | X | | |
| Salmon, sockeye | *Oncorhynchus (=Salmo) nerka* | E | X | | X | X | |
| Steelhead | *Oncorhynchus (=Salmo) mykiss* | T | X | | X | X | |
| Sturgeon, pallid | *Scaphirhynchus albus* | E | | X | | | |
| Sturgeon, white | *Acipenser transmontanus* | E | X | X | | | |
| Sucker, Lost River | *Deltistes luxatus* | E | | | X | | |
| Sucker, razorback | *Xyrauchen texanus* | E | | | | | X |
| Sucker, shortnose | *Chasmistes brevirostris* | E | | | X | | |

| Species | Scientific Name | Status* | Idaho | Montana | Oregon | Washing-ton | Wyoming |
|---|---|---|---|---|---|---|---|
| Sucker, Warner | *Catostomus warnerensis* | T | | | X | | |
| Trout, bull | *Salvelinus confluentus* | T | X | X | X | X | |
| Trout, Lahontan cutthroat | *Oncorhynchus clarki henshawi* | T | | | X | | |

Source: U.S. Fish and Wildlife Service, 2005. Threatened and Endangered Species System. Listing By State and Territory as of 4/28/05. http://ecos.fws.gov/tess_public/TESSWebpageUsaLists?state=all, April 28, 2005.
* T = Threatened, E = Endangered

### Facility Licensing, Relicensing and Decommissioning

The costs of mitigating potential effects on threatened and endangered fish species and their habitat due to dam construction and operation is causing hydroelectric power companies, government decision makers, river advocates, and affected communities to reevaluate the costs and benefits of dams.[63] This is particularly true for older hydroelectric operations that require relicensing. A case in point is the relicensing of hydroelectric power facilities under the jurisdiction of the FERC.

Under the Federal Power Act, a FERC project license incorporates the regulatory standards that were in place when the license was issued. FERC licenses typically last up to 50 years; consequently, older hydroelectric facilities do not generally comply with current standards of the FESA.[68] [69] FERC's relicensing of hydroelectric facilities, however, provides the opportunity to bring older facilities into conformance with current environmental laws and regulations. In recent licensing and relicensing cases under FERC review, FERC has imposed additional conditions to mitigate environmental damages to achieve compliance with the FESA.[69]

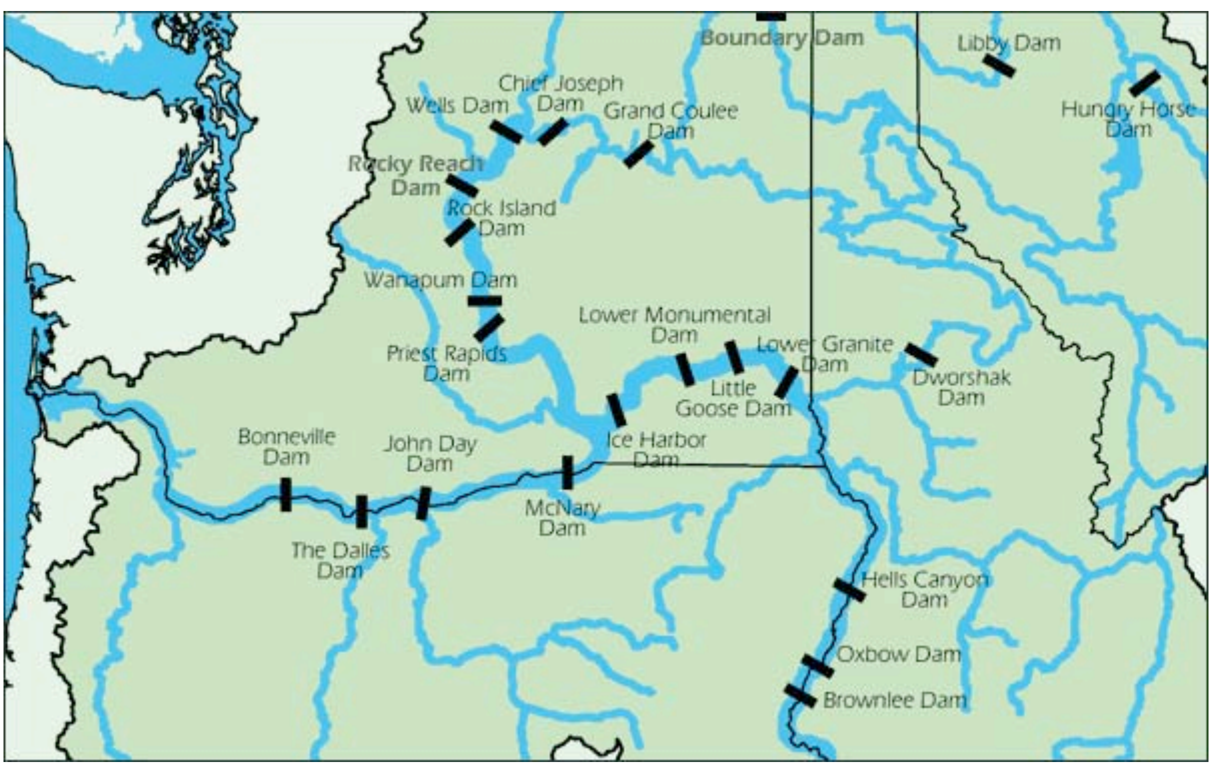
The cost of the mitigations and conditions imposed by FERC for relicensing has caused some hydroelectric operators in the Northwest to apply for decommissioning (abandonment) of these projects. These operators have concluded that the likely costs of providing the necessary level of protection, mitigation, and enhancement for environmental resources, particularly aquatic resources, outweigh the economic benefit of generation over the life of a new license. The Bull Run Hydroelectric Power Plant (Oregon), the Powerdale Hydroelectric Power Plant (Oregon), Condit Project (Washington), and the Elwha River (Washington) are recent FERC relicensing cases where the operator has opted for decommissioning due to the expense of mitigation. As an example, a description of the Bull Run project is presented below.

Bull Run Hydroelectric Power Plant, Oregon. The Bull Run Hydroelectric Power Plant is approximately 90 years old. It is located in the Sandy Basin of Oregon and consists of: the 47-foot high Marmot Dam; a concrete-lined canal that takes water from Marmot Dam through three tunnels to the Little Sandy River; the 16-foot high Little Sandy Dam; a 15,000-foot-long wooden-box flume; Roslyn Lake; and a 22-MW powerhouse.[70] The original FERC license for the project expired on November 16, 2004. On November 12, 1999, Portland General Electric Company (PGE), the owner, filed a notice of its intent not to seek a new FERC license for the facility because the projected cost of providing the level of mitigation required by relicensing would render continued operation of the project uneconomic.[71] PGE subsequently convened a Decommissioning Working Group (DWG) composed of governmental and non-governmental stakeholders in the project to develop a Decommissioning Plan that would maximize benefits to the resources affected by the facility consistent with PGE's obligations as a regulated public utility. The DWG successfully completed a Settlement Agreement and Decommissioning Plan that provides for: land donations, water rights transfers, fisheries, water quality and geomorphic monitoring, protection of threatened and endangered species, site restoration, resource/issue-specific studies, and historic preservation.[72]

**Columbia River Basin and the Lower Snake River**

A significant hydroelectric power source in the Northwest Region is the Columbia River Basin, which, at a regional scale, includes the Snake River. The Columbia River Basin's hydroelectric system is considered to be the nation's most productive source of hydroelectric power (known as the Federal Columbia River Power System (FCRPS)); the major hydroelectric dams of the FCRPS have a combined potential generating capacity of over 24,000 MW (see Figure 3-15).[73] Effects and mitigation programs specific to salmon and steelhead are of key importance to hydroelectric operations in the basin.

**Figure 3-15 Major Hydroelectric Dams within the Columbia River Basin**




Source: Northwest Power and Conservation Council, Map of the Major Dams of the Columbia River Basin, http://www.nwppc.org/library/2004/2004-1/default.htm.

The U.S. Army Corps of Engineers owns and operates the lower Snake River dams, which produce approximately 1,100 MW. [73] [74] Despite over $1.6 billion in funding to mitigate the lower Snake River dams, a highly public campaign to decommission the Ice Harbor, Lower Monumental, Little Goose and Lower Granite dams has been underway because of their effects on salmon and steelhead.[63] Construction and operation of the dams have been cited as creating a significant impediment to fish migration and passage along the river, which in turn has been attributed to major population declines in these species and their resulting status as threatened or endangered under the FESA. Additionally, Native American communities have raised issues associated with the effects of population declines on Tribal fishing rights and government treaty obligations.[63]

During the late 1800s, annual salmon and steelhead returns to the Columbia River were estimated to have been as high as 16 million fish per year. The returns have dwindled over time, dropping to approximately one million fish per year in the 1990s. These numbers increased in the late 1990s and early 2000s, partly because this was a period of favorable ocean conditions for salmon. The majority of returns today consist of hatchery-reared fish.[75] A study conducted by the U.S. Department of Commerce and the National Oceanic and Atmospheric Administration found that Chinook Salmon populations have trended down at a loss of two to 11 percent per year.[76] Although dams play a role in the reduction of fish populations, effects are also attributable to commercial fisheries, recreation, and agricultural uses as well as climate and ocean conditions.

To address salmon and steelhead issues, standards have been established for fish passage efficiency and fish survival through the use of mechanical bypass facilities and spill. The current version of the program, as amended in 2003, calls for dam-by-dam studies to determine the most efficient level of bypass spill in order to maximize passage efficiency and fish survival and preserve water for hydropower generation when it is not needed for spill.[77] However, some natural river migration advocates suggest that salmon species would benefit by removing (decommissioning), breaching a passageway through, or constructing bypasses to allow the river to flow past the four dams on the lower Snake River.[65] Those that advocate removing, breaching, or making a year-round passage way around the dams maintain that the four lower Snake River dams produce much less power than the other dams, and thus have raised questions regarding the long-term benefits of continuing operations of the dams.[78]

In summary, a trend in dam decommissioning is accelerating in the U.S., with 177 dams removed in the past decade, including 26 small dam removals in 1999.[63] Decommissioning is often due to relicensing of older hydroelectric facilities. More than 500 FERC licenses will expire in the next decade, [63] and it is anticipated that the decommissioning trend in the Northwest will remain significant because:

- Native American groups are intervening in dam relicensing and exerting Tribal fishing rights;
- Threatened and endangered species protection and watershed restoration are being made a higher public policy priority;
- Government agencies are funding decommissioning studies and dam removal,

- Operators are recognizing that in some cases the costs of implementing the mitigation measures and requirements for environmental protection stipulated by relicensing cause the economic viability of a given facility to be marginal or unacceptable.

# Natural Gas

## *Overview of Natural Gas Resources*

While natural gas is a key energy source for California, it comprises less than 20 percent of the electricity mix for the Northwest and Southwest Regions. Only Nevada uses natural gas for more than 35 percent of its electricity mix.

### Northwest Region

Table 3-13 provides information regarding the largest natural gas power plants in the western U.S. (excluding California) by generating capacity and state. In 2002, Idaho, Washington and Wyoming generated less than 5 percent of their power from natural gas, while Montana generated little or no power from natural gas plants.

British Columbia generates approximately 1,206 MW of power from natural gas plants. The largest share, 85 percent or approximately 1,026 MW of natural gas generation capacity, comes from steam generator units which do not have the fuel efficiency or environmental performance of a combined-cycle system.[79]

**Table 3-13 Largest Gas Generating Facilities – Northwest Region**

| State | Total Generating Capacity (2002 State Market Share)* | Total Generation (2002 State Market Share)* | State's Largest Natural Gas Power Generating Facilities, 2002* | | |
|---|---|---|---|---|---|
| | | | Facility Name | Owner/Operator | Generating Capacity (MW) |
| Idaho | 14.7% | 3.4% | Rathdrum Power LLC<br>Rathdrum<br>Mountain Home | Rathdrum Operating Services Co.<br>Avista Corporation 1<br>Idaho Power Co | 248<br>36<br>76 |
| Montana | | | (*None*) | *N/A* | *N/A* |
| Oregon | 13.9% | 16.6% | Klamath Cogeneration<br>Hermiston Generating | Pacific Klamath Energy Inc<br>Hermiston Generating Co LP | 470<br>464 |
| Washington | 4.6% | 4.6% | *N/A* | *N/A* | *N/A* |
| Wyoming | 2.8% | 1.6% | *N/A* | *N/A* | *N/A* |

* Natural gas plants only. The table does not include multiple fuel source power plants, such as combined oil and gas, or gas and coal-fired power plants.
Source: DOE, 2005b

## Southwest Region

Table 3-14 provides information on power plants in the Southwest Region. In 2002 all southwestern states except Utah generated more than 10 percent of the state's total generation from natural gas. Arizona uses natural gas for approximately 18 percent of its generation. The table provides a profile of some of the largest natural gas facilities in the Southwest and shows that although the Southwest is more reliant on natural gas than the Northwest, the Southwest uses natural gas for less than 20 percent of its electricity mix.

### Table 3-14 Largest Gas Generating Facilities – Southwest Region

| State | Total Generating Capacity (2002 State Market Share)* | Total Generation (2002 State Market Share) * | State's Largest Natural Gas Power Generating Facilities, 2002* | | |
|---|---|---|---|---|---|
| | | | Facility Name | Owner/Operator | Generating Capacity (MW) |
| Arizona | 21.6% | 18.4% | Redhawk<br>Desert Basin | Pinnacle West Energy<br>Reliant Energy Desert Basin LP | 918<br>598 |
| Nevada | 21.7% | 28% | Clark<br>El Dorado Energy<br>Tri Center Naniwa<br>Sun Peak Project | Nevada Power C0<br>El Dorado Energy LLC<br>Naniwa Energy LLC<br>Nevada Sun-Peak Ltd Partners | 700<br>450<br>300<br>222 |
| Utah | 13.7% | 3.8% | Gadsby<br>West Valley<br>Murray Turbine<br>Desert Power | PacifiCorp<br>PacifiCorp<br>Murray City of<br>Desert Power LP | 349<br>185<br>159<br>68 |
| New Mexico | 22.3% | 11.2% | Cunningham<br>Rio Grande<br>Maddox<br>Reeves<br>Afton Gen. Station<br>Milagro Cogeneration | Southwestern Public Service Co<br>El Paso Electric Co<br>Southwestern Public Service Co<br>Public Service Co of NM<br>Public Service Co of NM<br>Williams Field Services Co | 487<br>238<br>193<br>154<br>151<br>122 |
| Colorado | 25.1% | 19.8% | Fort St Vrain<br>Manchief Electric | Public Service Co of Colorado<br>Manchief Power Co LLC | 691<br>264 |

* Natural gas plants only. The table does not include multi-fuel source power plants, such as combined oil and gas, or gas and coal-fired power plants.
Source: DOE, 2005b

At the end of 2004, the Baja California Norte power system had 3,862 MW of generating capacity with 12 power plants including four combined-cycle plants fueled by natural gas, four geothermal plants, and four plants fueled by oil that use steam generator or combustion turbine technology (see Table 3-12). Mexico is a leader in the use of dry cooling systems due to the aridity of the region and lack of water sources. However, power plants recently built and proposed by U.S. developers have used wet cooling systems.[80] As noted on Table 3-15, northern Mexico exports 1,210 MW of electricity to California.[81]

## Table 3-15 Existing Generating Capacity – Baja California Norte

| Generating Station | Location | Type | Generating Units | Fuel | MW |
|---|---|---|---|---|---|
| **Public Service** | | | | | |
| Presidente Juarez | Rosarito | Steam | 4 x 75 and 2 x 160 | Oil | 620 |
| Presidente Juarez | Rosarito | Combined Cycle | 2 x 248 | NG | 496 |
| Mexicali (IPP-LRPC) | Mexicali | Combined Cycle | 1 x 489 | NG | 489 |
| Tijuana | Tijuana | GCT | 2 x 30 and 1 x 150 | Oil | 210 |
| Mexicali | Mexicali | GCT | 1 x 26 and 2 x 18 | Oil | 62 |
| Cipres | Ensenada | GCT | | Oil | 55 |
| Cerro Prieto I | Mexicali | Geothermal | 4 x37.5 and 1 x 30 | Renewable | 180 |
| Cerro Prieto II | Mexicali | Geothermal | 2 x 110 | Renewable | 220 |
| Cerro Prieto III | Mexicali | Geothermal | 2 x 110 | Renewable | 220 |
| Cerro Prieto IV | Mexicali | Geothermal | 4 x 25 | Renewable | 100 |
| **Export Facilities** | | | | | |
| La Rosita | Mexicali | Combined Cycle | 2x60 + 1x150 + 90/3 | NG | 560 |
| Termoeléctrica de Mexicali | Mexicali | Combined Cycle | 2 x 170 and 1 x 310 | NG | 650 |

Sources: (a) Public Service - Comisión Federal de Electricidad, Unidades Generadoras en Operacion, March 2004, p.65.;(b) Export Facilities – Imperial-Mexicali DEIS, May 2004, p.S-5.

### *Air Effects and Key Issues*

Natural gas is used as a fuel in boiler and gas turbine (simple-cycle and combined cycle) power plants. Natural gas is the cleanest power production fuel, overall, of the major fossil fuels used in the western states. While natural gas is the dominant fossil fuel used in California, coal is the dominant fossil fuel used in the Northwest and Southwest Regions. Natural gas power production has averaged approximately 13 percent of the total power imports from 2001 to 2003. Therefore, the overall western states power emissions (NOx, $SO_2$, $CO_2$, $PM_{10}$) are dominated by the higher polluting coal-fired power plants, while natural gas-fired power makes up a very small proportion of total imported power emissions. The western states' total power and imported power NOx, $CO_2$ and $PM_{10}$ emission statistics for 2001 through 2003 have been charted and are provided in Attachment C and Figures 3-3 through 3-12.

### *Water Effects and Key Issues*

The main water resource effects associated with natural gas power plants include consumption of large quantities of water for use in cooling systems and water pollution from chemical and thermal discharges. Once-through-cooling systems can impact local aquatic populations from entrainment and impingement, and chemical and thermal effects of the cooling water discharge. On average, each MWh of electricity produced from natural gas power plants using once-through cooling requires approximately 25,000 gallons of water.[82] Large combustion (500 to 1000 MW) combined-cycle facilities may use up to five million gallons of water on a daily basis.[83] Water is consumed in the generation process, while the remainder can be either discharged into a nearby body of water that most likely is also the point of withdrawal, or can be reused after treatment with a zero liquid discharge system.

Similar to coal, water consumption for use in natural gas power plants can exacerbate the existing water shortages in the Southwest and water competition with surrounding land uses such as agriculture, residential/commercial, or wildlife habitat. For example, in Idaho there have been two instances of water permits being denied for natural gas power plants due to conflicts with withdrawing water from a local aquifer. This situation has also occurred in the Southwest where a five-year drought has raised concerns about water use and withdrawals. In Arizona two natural gas projects, Big Sandy Power Plant (720 MW) and Toltec Power Plant (1,800 MW), were denied permits because of the concern with large amounts of groundwater used.[38]

There are various mitigation measures that have been proposed for natural gas-powered plants that include the use of alternative cooling water supplies, dry-cooling systems, or zero liquid discharge systems.[84] Alternative water supplies for cooling system consist of degraded or reclaimed groundwater. Cooling water discharges are primarily regulated through each facility's NPDES permit. Other mitigation takes the form of technologies such as filtration systems, less toxic additives to prevent algal growth and corrosion, more corrosion-resistant materials, and other treatment systems.[85]

**Mexican Border Power Plants**

Two recently-built combined-cycle power plants in Mexicali, Mexico, Intergen's La Rosita Power Complex and Sempra Energy Resource's Termoeléctrica de Mexicali use primary-treated wastewater from the local Mexican wastewater authority in their wet tower cooling systems. The La Rosita Power Complex can also accept raw wastewater. Each power plant pumps wastewater from the Zaragoza Lagoon to sewage treatment plants at each facility where it is treated to a tertiary level before being used as makeup water for both the cooling and steam cycles, or filtered for use as service water. Each power plant discharges into drainage channels that empty into the New River, which ultimately flows into the Salton Sea in California.[80]

The environmental effects in terms of water supply and quality of the La Rosita Power Complex and Termoeléctrica de Mexicali are currently not significant. Combined, both plants can withdraw up to 13,387 acre-feet per year from the total 30,200 acre-feet per year that flows from the Zaragoza Wastewater Treatment Plant lagoon. A maximum of 10,500 acre-feet per year is consumed in plant processes and the remainder is discharged. When the water consumed by the power plants is compared with the total annual inflow to the Salton Sea (1,363,000 acre-feet per year), it could result in about a one percent reduction in inflow to the Salton Sea, which is not considered significant. Water quality effects on the Salton Sea are also not considered significant. While the total dissolved solids (TDS), at the outlet of the New River into the Salton Sea would increase slightly due to reduced flows in New River attributable to the power plants and the effects of their wastewater discharge, the total TDS load contributed from Zaragoza Lagoon via the New River would decrease on the order of about nine million pounds per year. The total TDS load would reduce as a result of the power plants consumption of up to 32 percent of the Zaragoza Lagoon outflow. The Bureau of Land Management estimates the salinity of the Salton Sea could increase only 0.142 percent per year from operation of the Intergen and Sempra power plants.[80] Disease-carrying pathogens contributed from

Zaragoza Lagoon into the New River are also expected to be reduced by up to 32 percent due to the wastewater being treated and used at both power plants.[80]

### Biological Effects and Key Issues

Effects to biological resources due to natural gas power plants are primarily due to facility placement and construction and facility operation. Power plant placement and construction can lead to the permanent loss, or temporary disturbance of habitat due to the facility itself and its related infrastructure (such as natural gas pipelines, water supply and disposal pipelines, transmission lines and roads). Habitat loss, disturbances, and degradation can subsequently lead to direct and indirect effects on specific wildlife and plant species, including state and federally listed threatened or endangered species and locally designated species of special concern. These types of effects are illustrated by the conditions of approval specified for construction and operation of the Southpoint Power Plant, a 540-MW natural gas facility located in the Fort Mojave Indian Reservation, Mojave County, Arizona. To mitigate for biological effects identified in the project's Final Environmental Impact Statement, facility requirements include: preparation and implementation of a Desert Tortoise Mitigation Plan for direct compensation (take) and unmitigated effects; and, restrictions on pipeline and transmission line construction activities between January and June to minimize effects on bighorn sheep lambing areas.[86]

Although some biological effects cannot be fully mitigated, the majority can be minimized through careful siting (to avoid sensitive resources) and the application of pre-construction and construction phase measures to minimize those effects that cannot be avoided. Examples of these types of measures include monitoring, seasonal curtailment of activities, and off-site compensation (habitat restoration and/or contributions to existing or new habitat preserves in other areas).

Effects associated with operation vary widely as a function of a facility's specific design and technology and its surrounding environment. Overall operational effects to wildlife and plant species include issues such as salt deposition from drift and vapor emissions from volatile organic compounds.[87] Of key concern are operational effects to aquatic biological resources due to water intake and discharges. When power plants remove water from a natural water body, fish and other aquatic life can be injured and killed. Additional effects to aquatic life include thermal and chemical discharges.

Once-though cooling technology, in particular, uses very high volumes of water, leading to significant effects due to impingement and entrainment. At any given location, when the quantity of water withdrawn is large relative to the flow of the source waterbody, more organisms are affected; intakes in coastal waters, estuaries, and tidal rivers also tend to have greater ecological effects than those in freshwater lakes and offshore ocean intakes since these areas are usually more biologically productive and have more aquatic organisms in early life stages.[88] Facilities that use treated water for intake and do not discharge directly into natural water bodies inherently avoid these effects. However, for facilities that rely on natural water bodies for intake and discharges, effects are species/habitat-specific and typically require tailored mitigation to minimize their short- and long-term effects. Examples include modified water intake and output flow rates, screens (such as aquatic intake filter barriers), seasonal restrictions on water intake and output flows, alternative cooling technologies (dry cooling and hybrid cooling), application of Best

Conventional Pollutant Control Technology and Best Practicable Control Technology Currently Available, and the use of pre-discharge filtration systems.[88] [89] [90]

# Nuclear

## *Overview of Nuclear Energy Resources*

Nuclear power provides electricity only to two of the ten states considered in this report. Approximately 33 percent of Arizona's electricity comes from nuclear power while Washington depends on nuclear power for less than 10 percent of its electricity mix.

### Northwest Region

Only one operating power plant is located in the Northwest Region, the Columbia Generating Station in Washington (see Table 3-16). This facility provides power to Washington State. No other states in the northwest include nuclear power in their electricity mix. Nuclear power represents about nine percent of Washington's electricity.

About 13 percent of Canada's electricity comes from nuclear power. Canada has 17 nuclear power plants operating, which provide 12,000 MW of power,[91] which are located in Ontario, Quebec, and New Brunswick, in addition to research reactors in other provinces, including one in Alberta. There are no nuclear plants in British Columbia.[92]

**Table 3-16 Out-of-State Nuclear Power Plants**

| Plant | Operator | Capacity | Unit | Cooling System | Cooling Water Source | Condenser Flow Rate ($10^3$ gal/min) |
|---|---|---|---|---|---|---|
| **Arizona** | | | | | | |
| Palo Verde Nuclear Generating Station | Arizona Public Service Co. | 3,810* MW | 1, 2, and 3 | Mechanical draft cooling tower | Phoenix City Sewage Treatment Plant | 560 |
| **Washington** | | | | | | |
| Columbia Generating Station | Energy Northwest | 1,157 MW | 2 | Mechanical draft cooling tower | Columbia River | 550 |

Source: NRC, 1996a; Energy Northwest, 2005, SRP, 2005.
Note: The Palo Verde facility has 3 generators with a capacity of 1,270 MW per unit.

### Southwest Region

Table 3-16 presents information on the one nuclear plant within the Southwest Region. Of the two plants listed on the table, the Palo Verde Nuclear Generating Station in Arizona provides electricity to California. This facility is primarily owned by the Arizona Public Service Agency (29 percent). About 27 percent of this facility is owned by California companies. The part owners include: Southern California Edison (15.8 percent), Southern California Public Power Authority (5.9 percent), and LADWP (5.7 percent). In the Southwest Region, only Arizona uses nuclear power as a source of electricity.

Mexico has no nuclear facilities in northern Mexico (see Table 3-12). Mexico has two nuclear plants in Laguna Verde, Veracruz, each with 680 MW of capacity. In 2002, nuclear power provided 4.5 percent of Mexico's electricity.[23] According to the EIA International Energy Outlook – Electricity, Mexico has no plans to add nuclear power.

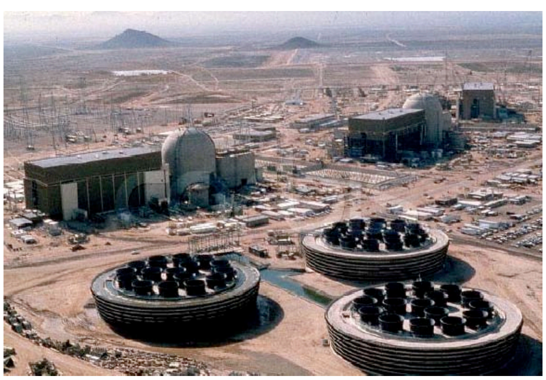
## *Air Effects and Key Issues*

Nuclear power production does not cause significant emissions of most air pollutants including NOx, SOx, $CO_2$, lead, and mercury. $PM_{10}$ emissions occur via droplet drift at facilities with wet cooling towers, and minor emissions may be associated with facility maintenance activities.

## *Water Effects and Key Issues*

A nuclear power plant generates electricity by using nuclear fission to heat water to steam and drive a steam turbine connected to an electrical generator. Enriched uranium fuel is surrounded by water in a water reactor. The fission process heats the water located inside the reactor and associated piping.[93] In some plants, such as the Columbia Generating Station (Columbia) in Washington State, the steam resulting from this water is piped directly to the steam turbine.[93] In other plants, such as the Palo Verde Nuclear Generating Station (Palo Verde), the water reactor is self-contained and pressurized and steam from the reactor transfers heat to water in a second, self-contained loop in the steam generator.[94] This isolates the radioactive water heated directly by the uranium from the non-radioactive water that turns the turbines. In both types of systems, however, the steam is cooled by passing through a condenser. The heat from the condenser is dissipated either as once-through cooling or through cooling towers.[93 94 95]

**Figure 3-16 Palo Verde Cooling Towers**



Similar to coal and gas, nuclear power generation requires the use of large quantities of water for cooling, both for plants using once-through cooling and for plants using mechanical draft (wet) cooling towers such as Columbia and Palo Verde generating units (see Figure 3-16). Table 3-13 lists the water use for each plant's generating unit.

Water quality issues associated with nuclear power generation are largely related to the control, treatment, and discharge of wastewater. Chemical discharges are regulated under the Clean Water Act under NPDES permits for each nuclear power plant. According to the Nuclear Regulatory Commission, small quantities of discharged chlorine or other biocides are considered of small significance and do not warrant mitigation.

Similarly, minor chemical spills and off-specification discharges that occur infrequently are also not considered to be significant.[96]

Water availability has been an issue associated with Palo Verde in Arizona. Palo Verde currently uses treated effluent from the Cities of Phoenix and Tolleson. In the absence of the plant, the treated effluent would be discharged into the Gila River where it would be used for groundwater recharge, irrigation, and support of riparian habitats. In the past, when all three Palo Verde units were operated simultaneously, flow in the river was depleted, pools and ponds dried up, and fish die-offs occurred.[96]

### *Biological Effects and Key Issues*

The cooling systems for Columbia and Palo Verde have been designed in a manner that substantially reduces the effects of thermal discharge on biological resources. Because Palo Verde is a closed-cycle cooling system that discharges into a cooling pond, the plant's cooling system does not result in any adverse thermal discharge effects. Columbia is also a closed-cycle cooling system that discharges into the Columbia River where the rapid flow of the river causes heat to dissipate quickly.[96] Consequently, any thermal discharge effects associated with Columbia would be relatively minor.

Impingement and entrainment issues are largely the concern of power plants utilizing once-through cooling methods. Both the Columbia and the Palo Verde plants use cooling towers, which release heat to the air.

Agricultural crops and vegetation communities can be affected by chemical salts and biocides resulting from dispersion in cooling tower drift. The recycled treated wastewater effluent used by Palo Verde has a relatively high salinity. Studies were performed to determine the potential for salt deposition from Palo Verde cooling tower drift to damage vegetation as well as agricultural crops such as alfalfa, cotton, and cantaloupe. Foliar injury and damage to vegetation via soil salinization was generally found only at the highest levels and was not found to substantially reduce agricultural yields.[96]

Mitigation features to reduce the effects of thermal discharge and entrainment and impingement on biological resources and water quality have been developed, but are largely unnecessary for Palo Verde and Columbia.[96] Palo Verde's use of treated effluent was designed to mitigate effects to fresh water supplies, but has inadvertently resulted in other effects, as described above.[96]

## Renewable Energy Resources (Wind/Geothermal/Biomass)

### *Overview of Renewable Energy Resources*

Renewable energy contributes approximately 13 percent to California’s energy mix. Less than one percent of California’s renewable energy comes from imported sources. The Northwest and Southwest Regions use renewable energy for five percent or less of their energy mix.  (Solar energy was not part of the scope of this document and is not addressed in this report.)

### Northwest Region

In the Northwest Region, the total capacity of renewable energy (biomass, geothermal and wind) is approximately 1,852 MW. Of this, 68 percent is generated from biomass and 32 percent is generated from wind. There is no geothermal energy capacity in the Northwest Region.

### Southwest Region

Currently, there is approximately 997 MW of geothermal generating capacity in the Southwest Region, all of which is allocated in Nevada, Utah, and Baja California, Mexico. In the U.S., Nevada has the greatest geothermal resource of any state. The state ranks second in the Southwest Region for installed capacity of renewable energy, with four percent of its electricity generation coming from geothermal facilities (there are 50 geothermal plants in Nevada). Baja California satisfies a significant portion of its energy needs with renewable energy. Currently, there are four geothermal plants located in Baja California (Mexicali) that have a generating capacity of 720 MW (see Table 3-12).

## *Air Quality Effects and Key Issues*

Wind energy does not create air pollution in contrast to other renewable energy sources, particularly those that require the combustion of a renewable fuel. In general, biomass technologies, such as green waste combustion steam boilers, have comparatively high pollutant emission rates but may not have very high net $CO_2$ emission rates, and in the case of some fuels like biodiesel may create net $CO_2$ emission reductions. Additionally, geothermal power can be a significant source of hydrogen sulfide and mercury emissions. However, renewable energy provides five percent or less of the total electricity generated in the Northwest and Southwest Regions and would not significantly contribute to air emissions.

## *Water Effects and Key Issues*

**Wind** power consumes no water or other scarce resources. Therefore, wind power has no significant effects on water resources.

**Geothermal** plants in Nevada and Utah use cooling towers or air cooled condensers to reject waste heat into the atmosphere. Therefore, unlike most fossil fuel plants, there is no thermal discharge into rivers or surface water. Thermal discharge can disrupt biota, such as algae and fish, in local water bodies. However, geothermal power plants can potentially cause groundwater contamination during well drilling and while operating (extracting hot water or steam). Geothermal power plants usually re-inject the hot water that they remove from the ground back into wells. Additionally, discharge wastewater from geothermal operations to surface or groundwater can also pose a significant impact to water resources, as it can carry contaminants and pollutants.

Groundwater contamination from drilling operations can be avoided by the use of cased and cemented geothermal wells, which precludes contamination of aquifers. Hot water and steam can only flow into the bottom of a geothermal well, significantly below coldwater aquifers, and is confined within one to three layers of casing cemented almost all the way down the well. If there was a natural connection (or one created by drilling) between the reservoir and a cold water aquifer, it could destroy the commercial viability of the geothermal reservoir. Operators avoid inflow of cold waters into a geothermal reservoir, or vice versa, both to comply with regulatory protections of groundwater aquifers and to protect the geothermal reservoir.[97]

**Biomass** power plants require the use of water for steam production and cooling. For every MWh of generated electricity, biomass power plants require between 18 and 214 gallons of water for a 75-MW gasification plant and a 50-MW direct-fired plant, respectively.[98] Whenever biomass power plants remove water from a water body for biomass energy generation use, it has the potential to directly affect fish and aquatic species inhabiting that water body through entrainment and impingement. In addition, the water used in the boiler and cooling system could result in effects due to chemical and thermal discharges.

### *Biological Effects and Key Issues*

The primary biological impact of **wind**-based power plants is avian and bat collisions. The populations of many birds and bat species have been adversely effected by energy facilities, including wind power generation.[99] Serious conflicts with avian populations are confined mainly to areas where large numbers of birds congregate or migrate, or where protected species are affected.

Unfortunately, many of the traits that characterize good wind sites are attractive to birds (see Figure 3-17). For example, mountain passes are frequently windy because they provide a channel for winds passing over a mountain range; for precisely the same reason, they are often the preferred routes of migratory birds.[99]

**Figure 3-17 Wind Turbine Field, Oregon**

For wind-based power plants, existing mitigation measures that are either being employed or researched to reduce effects to birds and bats include:

- Changing the color of the wind turbine blades
- Using tubular towers with diagonal stringers

- Eliminating places for birds to perch on the towers (especially perches near electricity transmission lines)
- Using radar to alert wind project operators to the passage of large flocks of birds.

The majority of biological effects associated with **geotherma**l power plants can be minimized or avoided through careful plant siting and design. Geothermal power projects typically require from about 0.2 to 0.5 acres of land per MW. Geothermal power plants, however, must be built at the thermal source since steam cannot be piped long distances without significant heat loss.

In general, biological effects to habitat and endangered and/or threatened species can be resolved through facility siting; geographic and season restrictions on specific types of construction and operational activities to avoid species-specific disturbances; and replacing habitat reduction due to facility placement and operation by rehabilitating or preserving similar habitat at another location.

**Biomass** fuels may be obtained from supplies of clean, uncontaminated wood supplies that otherwise would be landfilled or from sustainable harvests. However, the collection, processing and combustion of biomass fuels may involve toxic contaminants (such as pesticides and herbicides), other types of hazardous wastes, and undesirable pests and diseases. Another potential effect may be a loss of biodiversity. Transforming natural ecosystems into energy plantations with a very small number of crops, as few as one, can significantly reduce local and possibly regional biodiversity. However, mitigation measures such as those listed below have been identified to reduce the potential effects of biomass power generation:

- Ensure that wood, wood waste and other biomass sources are harvested according to an approved timber harvest plan in order to minimize effects to the flora and fauna of the area.
- Ensure that wood, wood waste and other biomass sources are harvested in areas specifically managed for forest fire fuel reduction or forest stand improvements.
- Do not transport insects or diseased nests outside zones of infestation.
- Rely on biomass fuel sources that operate according to local sustainability policies.[100]

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